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Preliminary Perspective on Pure Methanol Fuel for Transportation

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16. ABSTRACT

This report examines the relative advantages and disadvantages of the use of pure methanol fuel in motor vehicles designed for its use over conventional fuels. This report specifically addresses the use of pure or neat methanol it does not address methanol gasoline blends for use in existing automobiles. Five basic issues are discussed: 1. The availability of raw materials for methanol production such as coal, natural gas, wood, biomass, municipal waste and peat. 2. The relative availability of technology and environmental effects of producing methanol and conventional fuels from non-petroleum domestic feedstocks. 3. The practicality of distributing a new fuel for use in motor vehicles. 4. The exhaust emissions and fuel efficiency of motor vehicles operating on pure methanol fuel relative to those of conventional vehicles. 5. The economics of producing, distributing and using methanol as a motor vehicle fuel.

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EXECUTIVE SUMMARY
PRELIMINARY PERSPECTIVE ON PURE METHANOL FUEL FOR TRANSPORTATION

BY THE

OFFICE OF MOBILE SOURCE AIR POLLUTION CONTROL
U.S. ENVIRONMENTAL PROTECTION AGENCY

This report was prepared by EPA's Office of Mobile Source Air Pollution Control, whose primary responsibility is the control of pollution from the nation's motor vehicles. It is intended for use by the U.S. House of Representatives Subcommittee on Energy and Power, chaired by Representative John D. Dingell, which has been exploring the outlook for various alternative fuels.

The report examines the environmental advantages of pure methanol fuel in motor vehicles designed for its use over conventional fuels, and examines the issues involved in developing a methanol production industry, such as technological availability and economics, particularly when coal is used as a feedstock.

I. Conclusions

Based on early research by investigators at several institutions, it appears that the use of pure methanol fuel may offer certain significant environmental advantages over the present use of diesel and gasoline fuels. This conclusion presumes that methanol would be used in vehicles designed especially for its use. This conclusion is somewhat tentative due to the early nature of research on methanol-fueled vehicles and more experimental work to confirm this early research is needed.

Coal appears to be the most likely large-scale feedstock for methanol production. Although no methanol from a coal fuel facility currently exists in the U.S., the consensus of the chemical and fuel industries is that the production of methanol from coal is technically feasible. Although uncertainties still exist, adequate supplies of coal are available and the technology is relatively well understood compared to most other synthetic fuels processes.

Methanol from coal via indirect liquefaction is potentially more benign environmentally than direct coal liquefaction. However, no quantitative comparisons are yet available due to the fact that no completely integrated plants exist in either case in this country. Based on the available process design studies, almost all funded by DOE, pure methanol is projected to be less expensive than direct coal liquids and Mobil M gasoline. Of course, these comparisons will become more firm as these synthetic processes approach commercialization. However, the economic merits of moving to an alternative transportation fuel, such as methanol, from fuels derived from crude oil involve many uncertainties which must still be assessed. Should alternative transportation fuels become a viable national option, methanol could present very interesting possibilities compared to other alternative fuels.

II. Scope of the Report

This report surveys existing literature on the production of methanol and its use in motor vehicles compared to the production and use of other synthetic fuels from coal. The report does not address synthetic fuels from shale and thus, makes no conclusions in that area. However, as the conversion of coal will appear to play an important role in providing this country's alternative transportation fuels in the future regardless of the scenario chosen, the conclusions of this report should still be pertinent. The report also focuses on the use of synthetic fuels in motor vehicles, where the expertise of the Office of Mobile Sources lies, and does not address the use of synthetic fuels in other areas, such as electric power generation. EPA is currently conducting its own scientific work on the environmental aspects of the use of pure methanol in motor vehicles, but significant results are not yet available.

The report considers only the use of pure or neat methanol and does not deal with methanol blended with gasoline for use in existing automobiles. While methanol/gasoline blends could provide an important intermediate market for methanol fuel, we see the primary environmental advantages of methanol being associated with its use as a straight fuel in vehicles designed for its use.

The following sections present a summary of the findings of the report.

III. Environmental Advantages (End-Use)

Used in motor vehicles, pure methanol would reduce nitrogen oxide emissions roughly 50 percent compared to diesel fuel and gasoline, and produce almost no particulate matter, heavy organics or sulfur bearing compounds,. The absence of particulates and heavy organics is in sharp contrast particularly with diesel fuel.

Besides providing the above advantages over existing fuels, methanol could provide even greater environmental benefits over certain future fuels, particularly certain future diesel fuels. The quality of diesel fuel in the U.S. has been steadily declining over the last five years due to the processing of heavier and heavier crude oils each year. In the absence of widespread utilization of available technology to curb this decline which involves a significant cost, this trend is expected to continue, even if petroleum continues to be the main source of diesel fuel, and will likely accelerate with the advent of synthetic diesel fuels. This reduction of diesel fuel quality will generally result in an increase in diesel emissions, particularly that of particulate matter. Thus, methanol should provide even greater benefits relative to this lower quality fuel of the future.

Methanol engines, however, may emit more aldehydes than gasoline or diesel engines, including formaldehyde, a suspected carcinogen. Uncertainties exist as to whether the increases are significant, since the current level of formaldehyde emission from gasoline or diesel engines is not now thought to present a problem. Even if the aldehyde levels from methanol engines would appear to be a problem, research testing of catalytic converters show them to be able to remove up to 90 percent of the aldehydes, indicating that the problem may be solvable.

One potential secondary benefit of fueling a vehicle with methanol is the possibility that the catalyst used to clean up the exhaust could be of the base metal variety, such as copper, chromium, or nickel, and not made up of noble metals, such as platinum and palladium. Unlike gasoline, methanol does not contain any sulfur or lead, which degrade base metal catalysts very quickly. This would significantly reduce the cost of the catalytic converter system. However, more importantly, this change could improve the country's balance of payments, since all noble metals must currently be imported. And while some base metals are also imported, their value would be significantly less and still produce a net decrease in imports.

Pure methanol would require the use of vehicles designed specifically for its use, but these vehicles may be no more expensive than current vehicles and easily produced with current technology. All the major automobile manufacturers have indicated that the mass production of methanol-fueled vehicles would pose no unsolvable technical challenges.

IV. Raw Materials Availability

Domestic raw materials for methanol production are in plentiful supply, and include wood, biomass, municipal waste, peat, natural gas and most importantly, all grades of coal.

This range of possible raw material may offer the long-term advantage of a geographically diverse methanol fuel industry, since resources are spread across the country. Coal, though, is likely to be the first and major raw material for pure methanol fuel in the future. Thus, the major advantage of methanol over those synthetic fuels produced via the direct liquefaction processes is that its economics appear to be less dependent on coal type, opening up the nation's resources of lignite and even peat (considered a very young coal) to synfuel production.

V. Production Technology

The chemical industry already produces methanol from natural gas and residual oil, so this technology is fully commercial. However, since natural gas and petroleum supplies will not likely be available for large-scale production of methanol fuel in the future, the technological feasibility of producing methanol from more plentiful feedstocks is a more relevant question. Methanol production from three domestic feedstocks was examined: coal, wood and wastes (agricultural and municipal), as well as methanol from foreign remote natural gas.

A. Coal Processes

In general, among the newer processes, methanol from coal is more advanced than the processes using other raw materials.

Methanol is produced from coal via indirect liquefaction, a two step process consisting of first gasifying coal into carbon monoxide and hydrogen and then synthesizing this gas into methanol. The second step of the process, methanol synthesis, is the same regardless of the feedstock used to produce the synthesis gas. Thus, this step is commercially proven whether natural gas, residual oil, coal, wood, etc. is used as raw material to the methanol process. The first step, coal gasification, is also commercially proven, as first-generation gasifiers have been in operation for thirty years. However, more efficient second-generation gasifiers have been under development for over twenty years and a number of these gasifiers now appear to be ready for commercialization. Three such gasifiers are the Texaco, BGC-Lurgi and Shell-Koppers gasifiers. Thus, the production of methanol from coal appears to be achievable today and only waiting for the proper economic conditions.

The other indirect liquefaction processes also are commercial or near commercial. The Fischer-Tropsch process is definitely commercially proven, as full-scale plants are currently operating in South Africa using first-generation coal gasifiers. The other indirect process, the Mobil M-Gas process, converts methanol into gasoline. Up to the methanol conversion step, the technical feasibility of this process is the same as that for a methanol from coal facility, which was already described above. The final, methanol to gasoline step is not as commercially ready, however, having been only demonstrated in small pilot plant units. However, there appears to be firm interest overseas to scale up this technology directly to a commercial-sized plant. Thus, it may be at approximately the same state of commercial readiness as the other two indirect liquefaction processes.

Direct Liquefaction processes, on the other hand, are a number of years away from commercialization. Large pilot plant work is currently underway and progress is being made. However, significant technical problems still remain to be overcome. In addition, many of the key processing steps have not yet been integrated, but have only been tested individually. Thus, most plans call for a large-scale demonstration plant to be built to develop confidence in the entire process before any commercial plants would be planned. Overall, the direct liquefaction processes are not in the same state of commercial readiness as the indirect liquefaction processes.

With respect to overall conversion efficiencies, methanol synthesis is the most efficient of the indirect liquefaction processes. The production of methanol from bituminous coal is about 49-57 percent efficient, while the Fischer-Tropsch and Mobil M-Gas processes are roughly 5 percent less efficient. The direct liquefaction processes are projected to be more efficient, around 56-64 percent. However, given that the direct liquefaction processes are further from commercialization, there is a greater likelihood that these figures will decrease in the future relative to those for the indirect liquefaction processes.

B. Wood Processes

Like methanol from coal, the production of methanol from wood depends on the feasibility of the gasification step. Wood gasification is not as far advanced as coal gasification. However, in many ways the gasification of wood is inherently easier than the gasification of coal. Thus, while wood gasification is not commercially proven, its commercialization is primarily awaiting commercial stimulization and not the overcoming of large technical obstacles.

Direct liquefaction techniques based on wood, on the other hand, are far from commercialization. Thus, if wood is to be used in the near future to provide the nation with liquid fuel, it will have to be based on indirect liquefaction (i.e., methanol, Mobil M-Gas, or Fischer-Tropsch). However, the cost of producing methanol or other indirect liquids from wood appears to be significantly higher than that from coal. Thus, in the near term, the actual use of wood for synthetic fuel production will have to await a large relative increase in the price of coal or special incentives to make wood-based synthetic fuels more economical.

C. Agricultural and Municipal Waste Processes

The gasification of agricultural and municipal wastes is at about the same technological point as the gasification of wood. In other words, the production of methanol and other indirect liquids from these raw materials is feasible. However, the economics of synthetic production based on these raw materials would appear to be even less desireable than that based on wood. Thus, there is currently little commercial activity in this area and little likely in the near future.

D. Environmental Effects (Production)

While the report did not analyse the environmental impacts of synthetic fuel production in great detail and there is a general lack of firm information in this area, the report was able to make a few general findings. The production of synthetic fuels from coal will require the control of many pollutant streams regardless of the processes employed. However, there appears to be a number of aspects of indirect liquefaction processes relative to direct liquefaction processes which could make the control of certain pollutants easier and more likely to happen.

One, sulfur must be almost entirely removed to protect either the methanol or Fischer-Tropsch catalysts. Otherwise, the catalysts degrade uneconomically fast. Direct liquefaction processes leave most of the sulfur in the liquid hydrocarbon product. This sulfur can be removed by hydrotreating, which would upgrade the liquid product at the same time. However, the degree to which direct liquid is upgraded will depend on economics and it is entirely possible that the economics will call for a relatively poor quality product. In this case, the level of hydrotreating will be relatively low and much of the sulfur will remain in the product. The same conclusion generally holds for nitrogen impurities.

Two, the hazard of exposure to the fuel itself should be less with indirect liquids as compared to direct liquids. The products of most direct liquefaction processes are mutagenic prior to severe upgrading via hydrotreatment. The products of indirect liquefaction processes are not. And while substantial exposure to methanol is widely known to cause blindness and possibly death, methods for its safe handling have been practiced for years in the chemical industry.

Three, a methanol spill would be much easier to deal with than a spill of any hydrocarbon fuel. Methanol dissolves in water and would quickly disperse in the case of a spill on land or in water. While the methanol would cause severe damage in the immediate locale of the spill, it is quickly broken down to non-toxic compounds in the environment and plant and wildlife would return relatively quickly. Spills of hydrocarbon fuels, as is well known, do not dissipate quickly and their effects remain for some time.

V. Economics

All design studies available when this survey was performed which estimated the cost of producing synthetic fuels from coal were examined and placed on a comparable economic basis. Using these estimates, it appears that the production of methanol from coal would be less expensive than the production of gasoline via the Fischer-Tropsch, Mobil M-Gas, or direct liquefaction processes. While the distribution of methanol would cost more than the distribution of gasoline, this additional cost does not appear to outweigh the production savings.

In addition, the use of methanol in vehicles should almost certainly allow the fuel efficiency of the engine to increase relative to that of a gasoline engine, producing even greater savings.

Preliminary Perspective on Pure Methanol Fuel For Transportation

This report surveys and analyzes available literature prepared by other government agencies and industry on pure methanol fuel. (It does not deal with methanol blends in gasoline which may have substantial environmental problems if the concentrations are too great.) EPA has begun very early scientific research of its own on pure methanol, and the results of this research were not available at publication time.

This report is intended to provide background material on the possibilities of methanol as a transport fuel, and includes limited discussions on the production technology, economics as well as environmental effects of using methanol. It provides a theoretical discussion of environmental effects during production, but actual pollution discharge rates from methanol plants are not yet available. This report therefore, provides only limited comparisons of methanol against certain synthetic fuels, and does not attempt to devise a total synthetic fuel or national energy policy.

The report only examines pure methanol fuel as one possible solution to the energy problem in the transportation sector. The report concludes that pure methanol may potentially offer some environmental advantages during end-use in motor vehicles, and under certain conditions, may be economically competitive with direct coal liquids, although many cost uncertainties are still unresolved. The economic merits of moving to an alternative transportation fuel, such as methanol, from crude-derived fuels involve many uncertainties which must still be assessed. Nonetheless, EPA encourages the experimental use of pure methanol in motor vehicles especially designed for this purpose.

The mobile source office of EPA first developed an interest in methanol as an alternative transportation fuel over ten years ago because of its potential for achieving low motor vehicle emissions. More recently, our interest has increased due to a particularly difficult problem concerning the reduction of emissions (in particular nitrogen oxides and particulate emissions) from heavy-duty diesel engines.

The Clean Air Act as amended in 1977 (hereafter referred to as the Act) requires that the emissions of nitrogen oxides (NOx) from new heavy-duty engines be reduced by 75 percent beginning in 1985. EPA has been working closely with the manufacturers of heavy-duty engines over the last two years to assess their ability to meet this goal. While it appears that the full 75 percent reduction can be achieved by heavy-duty gasoline engines with technology similar to that used on today's automobiles, the task is much more difficult for heavy-duty diesel engines. The only technology known today which could even conceivably achieve the required degree of control without a significant fuel economy penalty is an exotic ammonia/reduction-catalyst system. However, this system would be extremely expensive and possibly a safety hazard and has therefore been rejected from further consideration. Other more reasonable, but still advanced, technology, such as digital electronic engine controls, intake air cooling and exhaust gas recirculation, appear to have the potential to achieve at most slightly over half of the required reduction. However, these techniques would still cost roughly $700 per engine and could increase fuel consumption up to 10 percent at this level of emission reduction. Thus, even the achievement of only half of the goal set forth by Congress would be fairly expensive because the technology is simply not available today or in the foreseeable future to inexpensively reduce NOx emissions from a diesel engine.

Aggravating this problem are the high levels of particulate matter being emitted from these heavy-duty diesel engines. These particles are very small and easily respirable into the deepest regions of the lung. Heavy polycyclic organic materials which have been shown to be mutagenic are also present on these particles. This has led to a concern that diesel particles may cause cancer, which EPA is currently investigating. While the Agency has not yet completed its study in this area, it is evident that emissions of this particulate matter merit some degree of control regardless of their carcinogenic potential, due to their small size and prevalence at ground level in urban areas.

The most promising approach to controlling these particles is the trap-oxidizer, which is a device which first traps the particles and then burns them off periodically or continuously. However, this device is expected to cost as much as $500-600 per heavy-duty engine. Coupled with the cost of controlling NOx emissions, the cost of a vehicle equipped with a heavy-duty diesel engine could increase 1-7 percent due to the control of these two pollutants.

Another concern which may present a problem with the use of trap-oxidizers is that certain catalyzed trap-oxidizers may increase sulfate emissions (sulfuric acid).[1,2] The potential exists for higher sulfuric acid emissions from diesel engines with catalyzed trap-oxidizers as compared to catalyst-equipped gasoline engines due to the higher level of sulfur in diesel fuel as compared to gasoline (7.7 g/gal vs. 0.5 g/gal).[3,4]

These are actually not only problems for heavy-duty diesel engines, but for light-duty diesels (cars and light trucks) as well. EPA has had to grant waivers of the Congressionally-set 1.0 g/mi NOx standard through 1984 for most diesel passenger cars because this standard was too difficult and costly for them to achieve in the time available, without significantly increasing particulate emissions. And light-duty diesels emit the same small, organic-laden particles as the heavy-duty diesel engines.

Diesel engines are also expected to significantly increase their share of the heavy-duty engine market (from 35 percent now to 54 percent by 1990), and the light-duty market as well.[5,6] It is also expected that the current indirect-injection diesel engines used in today's light-duty vehicles will be gradually replaced with direct-injection engines (as is currently the case for heavy-duty diesels). The direct-injection engines will displace the indirect-injection engines primarily because they are more efficient (10-15 percent better fuel economy). The two primary reasons that indirect-injection engines are dominant today in the light-duty vehicle market are that they have lower emissions and are quieter. Thus, as light-duty diesel engines convert to direct-injection, higher emissions and more difficult control will be inherent.

Compounding these problems is the general expectation that diesel fuel quality will progressively decline. In the next few years as the demand for diesel fuel increases relative to gasoline, diesel fuel composition will likely change and, in particular, the fuel is expected to be a "broader cut" fuel that is, the fuel would have an increased amount of lighter hydrocarbons (from previous gasoline feedstocks) and heavier hydrocarbons (from previous fuel oil feedstocks). Also, as the better quality crude oil reserves are depleted, the sour, heavier crudes may yield poorer quality diesel fuel. And finally, as synthetic crudes (from oil shale and coal) enter the fuel system, even more significant diesel fuel quality compromises could occur. While diesel engines are expected to be able to burn these liquids, the combustion quality will probably deteriorate and emissions may increase. Technology is available to counteract these trends, but the cost involved makes its application unlikely.

It was from this perspective that the Agency began inquiring into the use of an alternative fuel for diesels that could solve the emission problem at a potentially lower cost than the use of engine modifications and add-on devices. While most EPA emission standards have focused on the engine and required control there, there are generally two ways to approach any emissions problem: modify the engine or modify the fuel. In most of the situations of the past, the easiest solution was to modify the engine (the one major exception being the Agency's requirement that unleaded gasoline be available for 1975 and later model light-duty catalyst-equipped vehicles). However, in the case of the current diesel engine emission problems, engine modification may not necessarily be the least expensive way of achieving the goals of Congress.

While a number of alternative natural and synthetic petroleum-derived fuels were considered, none appeared to have the potential to control these emissions any more cheaply than the engine-related techniques already discussed. However, one nonpetroleum fuel, methanol, appeared to show promise for a number of reasons. One, methanol is well known as a high-performance fuel, and a methanol-fueled engine should have a good chance of achieving the fuel efficiency of a diesel engine. Two, methanol burns much cooler than diesel fuel because it already contains some oxygen and this would likely have a direct, positive effect on NOx emissions. Three, methanol is a lighter (lower boiling point) fuel than diesel fuel and, based on our experience with petroleum-based fuels which are lighter than diesel fuel, should both produce less particulate matter and less heavy polycyclic organic material than a diesel engine operating on diesel fuel. Four, it is well known that methanol is producible from a wide variety of raw materials, including the nation's vast resources of coal. This is not to say that methanol was seen as a quick and easy solution to the emissions problem of the diesel. However, methanol as an alternative fuel did meet more of the basic requirements than any other fuel and appeared to merit further consideration.

In approaching this alternative with the diesel manufacturers themselves none doubted the low-emission potential of methanol. And while some wondered whether a methanol engine would still be a "diesel" engine as they knew it, none doubted that a methanol engine could be built and have good thermal efficiency. (Whether or not the efficiency would actually equal that of a turbocharged direct-injection diesel was open to debate.) Many manufacturers had in fact already considered methanol to at least some extent, but had rejected it. Their rejection was often partially based on the fact that methanol is not a good fuel for today's diesel engine. (It has a low cetane number, which means that it does not readily ignite under high compression as diesel fuel does.) However, most had rejected methanol in a more absolute fashion based on a conviction that it would cost up to twice as much as synthetic diesel fuel from coal or oil shale. Thus, while methanol appeared to have significant potential as a low-emission fuel and the diesel manufacturers were willing to talk about what a methanol engine would mean technologically, fuel cost seemed to be an inescapable problem.

However, while the studies cited by the diesel manufacturers did conclude that methanol from coal would be far more expensive than synthetic hydrocarbon fuels, the Agency was also aware of studies which concluded that methanol would be no more costly to produce than synthetic hydrocarbon fuels, and possibly even cheaper. A search of the available literature revealed no study that reconciled these conflicting results. This analysis by EPA's Office of Mobile Source Air Pollution Control (OMSAPC) attempts to make such a reconciliation, and to determine if conditions exist under which methanol may be economically competitive with, or less costly than, gasoline or diesel type fuels, both natural and synthetic. This analysis does not attempt, however, to predict whether these conditions will or will not occur. This assessment was necessary to allow a preliminary determination as to whether or not pure methanol could be a practical alternative fuel for diesel engines.

This study is not a comparison of methanol to all other potential motor vehicle fuels. It is not even a comparison of methanol to all other synthetic fuels. At this preliminary stage, the analysis is limited to a comparison of methanol to other synthetic transportation fuels from coal. Both direct and indirect coal liquefaction processes are examined, specifically the Mobil Methanol-to-Gasoline (MTG), Exxon Donor Solvent (EDS), H-Coal, and Solvent Refined Coal II (SRC-II) processes. The Fischer-Tropsch (F-T) process was not fully considered because only a fraction of this process' products are transportation fuels[7] and because the available references show it to be economically inferior to the other synthetic petroleum processes mentioned above, particularly the Mobil MTG process.[8,9,10] We are aware of some who say that Fischer-Tropsch can be competitive with the other processes with catalyst improvements and with a market for the methane produced.[11] We plan to investigate this possibility further in the future. However, at this time the comparison of methanol against the Mobil MTG process should be adequate to demonstrate whether or not methanol is competitive with other indirect liquefaction processes which produce fuels compatible with today's engines and distribution system.

This study also excludes any comparison of methanol with fuels derived from shale oil. The production technologies are quite different and the comparison needs to be postponed to a later date when more information is available.

This report is only an examination of the advantages and disadvantages of pure methanol as a transportation fuel in comparison to other synthetic fuels from coal. It does not attempt an in-depth comparison between methanol and non-coal synfuels, or other energy policy options. In summary, therefore, this report does not attempt to evaluate methanol against all other alternate fuels strategies.

Methanol from coal will be discussed as a possible fuel for both gasoline and diesel engines. If methanol were to become generally available and methanol engines were used in current diesel engine applications, it is extremely likely that methanol engines would also capture a portion of the existing gasoline engine market. Therefore, from the point of view of economics, methanol is in competition with some combination of gasoline and diesel fuel and not only one or the other.

The purpose of this paper, then, will be to generally examine the technological and economic feasibility of methanol as an automotive fuel, and particularly examine its potential to solve the diesel emission problems described above. This will be done in five steps. First, the availability of raw materials and its potential impact on the economic feasibility of methanol and other synthetic fuels will be discussed. Second, the technology needed to produce these fuels will be discussed. Third, the effect and cost of adding methanol to the automotive fuel distribution system will be examined and compared to the effects of adding other synthetic fuels to the distribution system. Fourth, the use of methanol in motor vehicles and its effect on emissions and fuel efficiency will be assessed. And last, the overall economics of the production and use of these various synthetic fuels will be presented from a preliminary viewpoint.

I. Raw Material Availability

As previously mentioned, the primary purpose of this paper is to compare two coal strategies; one which converts coal into methanol and one which converts coal into conventional hydrocarbon fuels. As such, this section will primarily deal with the availability of coal, particularly any differences which may exist relative to the two strategies. In addition, it will also discuss other sources of methanol, both short-term and long-term. This will be done from the point of view that, if methanol were to become generally available from coal, it may open up markets for methanol from other raw materials that do not currently have a market. Since gasoline can be produced from methanol via the Mobil MTG process, this discussion would apply equally to gasoline via this process. This secondary discussion will not be performed specifically for the hydrocarbon fuels since their markets are well established and any economical process for producing these fuels can easily fit into the existing refinery/distribution network.

Estimates of the recoverable reserves of coal in the U.S. are shown in Table 1 by coal type. As can be seen, almost two-thirds of all recoverable U.S. coal is bituminous, while one-third is sub-bituminous (based on energy content). Anthracite and lignite together represent about 6 percent of the total U.S. recoverable reserves.

These coal reserves are spread across much of the continental U.S. (see Table 2). Roughly one-quarter (by weight) is located in the Appalachian region. This coal is primarily bituminous, but this region also contains the anthracite reserves shown in Table 1. Coal in this region is primarily underground, with only one-quarter being surface-minable.

The central midwest (primarily Illinois) also contains about one-fourth of recoverable U.S. coal. This coal is primarily bituminous, with one-third being surface-minable and the rest underground-minable.

The northwest (Montana, North Dakota, Northeast Wyoming) contains a full one-third of the recoverable U.S. reserves. While this region contains most of the nation's lignite, its coal is primarily subbituminous. Half of this coal is surface-minable.

Finally, the central and southwest contain the remaining U.S. reserves; about one-sixth of the total. This coal is a mixture of subbituminous and bituminous, with the former being more predominant than the latter. Roughly one-third of this coal is surface-minable.

The total recoverable U.S. coal reserves shown in Table 1 amount to 5,306 quads (quadrillion Btu) of available energy.

Table 1

Estimated Recoverable Reserves

Coal Type	Billions of Tons	Energy (Quads)
Anthracite	3.7	107
Bituminous	114.3	3200
Subbituminous	84.2	1768
Lignite	16.5	231
	218.7	5306

Source: "The Direct Use of Coal," Office of Technology Assessment, 79-600071, p. 63.[12]

Table 2

Locations of Recoverable U.S. Coal Reserves

Region	Fraction of U.S. Reserves	Fraction of 1976 U.S. Production	Coal Type
Appalachian	One-fourth	0.60	Primarily bituminous, all of U.S. anthracite
Central Midwest	One-fourth	0.22	Bituminous
Northwest	One-third	0.08	Primarily subbituminous, majority of U.S. lignite
Southwest and Central West	One-sixth	0.10	Subbituminous and bituminous, some lignite

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Source: "The Direct Use of Coal," Office of Technology Assessment, 79-600071, pp. 61-63.[12]

Using a nominal liquid fuel conversion factor of 60 percent, this coal represents 2,653 quads of liquid fuel, which is equivalent to 450 billion barrels of fuel oil (at 5.9 million Btu per barrel). Since the nation consumes approximately 16 million barrels per day of liquid fuel (and about the same amount of nonliquid fuel), there is easily enough coal to provide the country's transportation fuel needs (either through methanol or synthetic crude) well into the future.

However, this is not only true in the sense of having sufficient overall reserves, but it is also true in the practical sense of minability. In 1981, 820 million tons of coal were mined in the U.S.[12] having a total energy content of nearly 19 quads or 10 million fuel oil equivalent barrels per calendar day (FOEB/CD). To provide 10 percent of the nation's transportation needs (which in total is approximtely half of the nation's liquid fuel needs or 8 million FOEB/CD), 147 million tons of coal would nominally have to be mined (at a 50 percent conversion efficiency). This would represent a 18 percent increase in total U.S. coal production, a modest increase. In addition, improvements in vehicle fuel economy, and conservation due to rising prices, will also reduce the amount of coal necessary for liquid transportation fuels. Converting as much as half of our transportation fuels to coal-derived liquid fuels would still require less than a doubling of our 1981 coal production. Thus, coal is indeed a viable source for our nation's alternative fuel program.

In addition to the general availability of coal for conversion to all liquids fuels, there are a few specific points which should be made with respect to coal's specific availability for conversion to methanol (or other fuels produced from methanol or synthesis gas, i.e., Mobil MTG gasoline and F-T liquids). One, methanol and other indirect coal liquids can be produced from all types of coal and, as will be seen later in Section V, the cost of methanol from all coal types is relatively constant. While the direct liquefaction technology appears to be available for all types of coal to be converted to liquids, the cost curve would not be flat. The cost of direct liquefaction liquids appears to be sensitive to hydrogen consumption and hydrogen consumption increases with oxygen content.[13] Thus, lower rank coals, such as subbituminous and lignite, which have higher oxygen contents, may be less likely to be converted via direct liquefaction than high grade anthracite and bituminous coal due to economics.[13] This would generally give the indirect liquefaction processes an advantage of greater flexibility over the direct liquefaction processes, though, of course, the final comparison depends on where the two cost curves cross.

While the cost estimate presented in Section V will shed some light on this issue, some indication can be obtained from the projected sites of the various synfuel projects. Using EPA's April, 1981, compilation of U.S. synthetic fuel projects,[14] it can be seen that all of the large direct liquefaction projects were projected to be located in the Appalachian/Western Kentucky region, which contains high grade coal. On the other hand, the indirect liquefaction projects are spread across all of the coal/peat regions of the U.S. This does not mean that direct coal liquefaction would necessarily be uneconomical in the other regions. That cannot be deduced solely from this information. It does confirm, however, the preference of direct liquefaction for bituminous coal and the non-preference of indirect liquefaction processes. (The fact that the compilation is over a year old and would now be out of date due to changes in the economics of crude oil should not affect the point being made.)

For example, this flexibility of indirect liquefaction would make available U.S. lignite fields for transportation fuel production. There are 7.1-12.5 billion tons of economically-recoverable lignite resources in the U.S., mostly in North Dakota.[12,15] At a 47 percent conversion efficiency, which is feasible today based on "wet" (undried) lignite,[16] this resource could provide a total of 1.6 trillion gallons of methanol or 19 billion barrels of gasoline equivalent.

Tentative plans already exist for one commercial-scale lignite-based synthetic fuel plant. The Nokota Company intends to build a 10,900 ton per day methanol-from-lignite plant at Dunn Center, North Dakota.[17] Construction is scheduled to begin in 1985 with a final completion date of 1991. Nokota has extensive holdings of lignite in North Dakota totalling 3 billion tons. The planned plant will consume about 368 million tons of this coal over 25 years.

Another example of coal reserves that appear to be economically convertible to methanol or other indirect liquefaction products are the large stores of mining residue in the anthracite coal regions of Pennsylvania. A study performed by the American Energy Research Corp. for the Department of Energy found methanol production from these coal refuse piles to be feasible and economical with today's technology.[19] From the 100 million tons of coal contained in these refuse piles, approximately 24 billion gallons of methanol could be produced or the equivalent of 290 million barrels of gasoline. Besides bringing badly needed economic benefits to this region, the removal of the refuse piles would be of great aesthetic and economic value to the towns and cities of the region. Most of the piles are actually within city limits and cover land which would otherwise be taxable and valuable for development.

While coal would be the primary feedstock for methanol fuel production, once a methanol fuel market developed, smaller amounts of methanol could be produced from a number of other sources. In fact, methanol from these other sources need not necessarily wait until a methanol fuel market develops. This is evidenced by a publicly-announced offer to build barge plants to process methanol from remote sources of natural gas and to build peat-to-methanol plants in the near future.[14,20] Methanol from these plants is aimed primarily at the chemical industry, where the majority of the methanol produced today is used. However, the promoters of these plants are also looking at the fuel market[17,20] and as a methanol fuel market would develop, the potential for producing methanol from these sources would of course increase.

For example, 7.2 trillion cubic feet of natural gas is flared each year around the world, because it is not economical to ship it for sale elsewhere[20,21]. While some natural gas is compressed and liquified and shipped in special tankers to this country (about 2 percent of total U.S. natural gas use,[21] it is actually cheaper to convert the natural gas to methanol and then ship it as a liquid when transportation distances are greater than 3,000-4,000 miles.[22] Litton and others have already had engineering plans drawn up to build methanol plants on barges to service these areas and could have them operating by 1984.[20] It is not likely that all of this gas will soon be converted to methanol nor all of that converted shipped solely to the U.S. However, to put this amount of gas into prospective, the flared gas mentioned above would provide 88 billion gallons of methanol per year, or the energy equivalent of 2.8 million barrels of gasoline per day (about one-third of U.S. transportation fuel consumption).

Peat, too, may be economically convertible to methanol, and presumably, other indirect liquefaction products, if desired. The U.S. has one of the largest peat reserves in the world, 52.6 million acres containing approximately 1,450 quads of energy.[23,24] The Energy Transition Corp. is tentatively planning a commercial peat-to-methanol venture in North Carolina.[14] The plant will use Koppers/Babcock-Wilcox gasification technology and produce 3,700 barrels (500 tons) per day of methanol. While proof of the economics of peat-to-methanol conversion will only come if and when this plant is built, peat's consideration for this project does at least demonstrate its gross feasibility.

Also, while no commercial plants are currently planned, wood may also be a possible long-term resource for indirect liquefaction conversion. According to a study done by MITRE Corporation, the current potential gasification feedstock (made up from residues, surplus growth, annual mortality and noncommercial lumber) is 500 million tons of wood per year.[25] With the introduction of silviculture energy farms a stable and renewable 550 million tons/year of wood could be realized by the year 2000. Using a conversion efficiency of 55 percent (164 gal. methanol/ton wood), this wood could be transformed into 82 billion gallons of methanol/year (2.7 million bbl. gasoline/day) in the short term or 90 billion gallons of methanol/year (2.9 million bbl gasoline/day) by the year 2000. The first figure represents about 34 percent of U.S. current transportation energy requirements while the second value would be about 36 percent.

For long-term wood availability, OTA estimates that the maximum growth potential of U.S. forest is 1.1 billion to 2.3 billion tons of wood per year.[26] The percentage of felled timber today that is left in the forests or unused is approximately 40 percent. Therefore, if this percentage of unused or waste wood remains and the same 55 percent conversion efficiency is used, there could be up to 870 million tons of wood or 150 billion gallons of methanol (4.9 million bbl gasoline/day) available each year. This represents about 61 percent of the nation's current transportation energy needs. Thus, in the long term, methanol from wood looks promising, not only because wood could provide a stable and renewable energy source, but also because methanol from wood (or gasoline from the methanol) could supply close to one half of our current transportation energy needs.

Another renewable feedstock for indirect liquefaction besides wood is agricultural waste. Although much of the current emphasis has been on the production of ethanol from agricultural wastes, various studies have shown that these wastes can be processed more efficiently into methanol. DOE estimates, for example, that the same amount of residue could produce over twice as much methanol on a Btu basis as ethanol.[27] This should roughly hold true for Mobil MTG gasoline, also. DOE further projects that by the year 2000, over 278 million tons of agriculture residues could be converted to 48 billion gallons of methanol per year.[27] This is about 20 percent of our current transportation energy needs.

Methanol production from agricultural wastes is not without its uncertainties, however. These include the high acquisition cost of many crop residues and the substantial storage requirements as a result of seasonal production. Also, the long-range environmental consequences of not returning agricultural residues to the soil are unknown; in some areas the lack of these residues may cause erosion problems.[27]

Plans for one commercial methanol plant based on agricultural waste and biomass appear to be in progress. BioTex Energy Corporation has been working with DM International to construct a 60 million gallon per year (2000 bbl/day gasoline) methanol plant using stover from various grains, hay and Johnson grass.[28]

The final raw material to be discussed, municipal solid waste (MSW), avoids many of the uncertainties associated with agricultural wastes. Since municipal waste can be gasified into carbon monoxide and hydrogen, it is a viable feedstock for methanol. Like agriculture waste, MSW has a limited availability, but also likewise it can be processed into a substantial amount of methanol. According to the same DOE report mentioned above, 116 million dry tons of MSW could be available by the year 2000.[27] This could be transformed into 11.6 billion gallons of methanol per year or about 5 percent of our current transportation energy needs.[27]

Because of its heterogeneous nature, MSW must go through a series of preparation steps before it becomes a suitable energy feedstock. These steps, primarily designed to remove metal, glass and other impurities, are currently a major constraint to the use of MSW for energy purposes. However, it should be noted that these so-called impurities are also valuable products. As the value of these recoverable byproducts increases in the future, along with the value of the methanol or other primary product produced, converting MSW into useful liquid will become more economical. It should also be noted that the need for smaller landfills would be an additional economic benefit of MSW conversion and resource recovery. Some areas, such as New York City, are simply running out of useable landfill and will soon require some alternative.[29] And while there are other alternatives to indirect liquefaction of MSW, such as power generation or biological conversion to methane, methanol and other liquid fuels are definitely possibilities.

Overall, it can be seen that methanol and other indirect liquefaction products can be produced from a wide variety of natural resources. This has a number of advantages. One, it gives methanol and Fischer-Tropsch processes a flexibility not available to direct liquefaction processes. Two, much of the long-term resource is renewable, or at least self-generating, such as wastes, and would not be subject to depletion. (Methanol from these sources currently appears to be more expensive than methanol from coal and it may be a number of years before methanol is economical from these sources.[30]) Three, the wide variety of raw materials available for conversion to methanol or other indirect coal liquids will spread the economic and social impacts across the nation. Even without considering renewable resources, the viability of using anthracite, high-sulfur bituminous coal, low sulfur bituminous coal, lignite and peat will spread the economic benefits of synthetic fuel production to the midwest, southwest, and north central coal regions, as well as to the Appalachians and central west, where the benefits of direct coal liquefaction and shale oil would be highly concentrated. Thus, from the aspect of raw materials, methanol and other indirect liquids processes would appear to have some advantages over direct liquefaction processes.

II. Production Technology

Although methanol may be produced from a wide variety of raw materials, there are essentially only two practical methods of production, both of which involve the production of a synthesis gas.[31,32] Under the first method, the feedstock (regardless of type) is gasified via partial combustion with oxygen or air at high temperature to produce a synthesis gas containing mainly carbon monoxide and hydrogen. This synthesis gas is reacted with steam to shift the ratio of carbon monoxide and hydrogen closer to the optimum 1:2 ratio. Then the synthesis gas is purified to remove all the acid gases, such as hydrogen disulfide, and other impurities, such as carbon dioxide, methane, etc. The resulting carbon monoxide-hydrogen mixture is then converted to methanol as it is passed over a catalyst under pressure. The final product is relatively pure methanol (97 percent) with no impurities other than a slight amount of water and higher alcohols. The second process, steam reforming, also produces a carbon monoxide-hydrogen synthesis gas which is then converted to methanol in the presence of a catalyst. In this case, the feed stock (usually natural gas) is reacted with steam to yield the above-described synthesis gas.

The two basic steps needed to make methanol, then, are production of the synthesis gas and conversion to methanol. It is the first step (gasification or reforming) which has to be optimized for the individual feedstock. Since the purified synthesis gas always contains only carbon monoxide and hydrogen (and minor impurities), the second, synthesis step for all methanol processes is the same.

Methanol, unlike either synthetic crudes or MTG gasoline, is currently being produced in large quantities. However, nearly all of it is being produced from natural gas or residual oil. No domestic large-scale plants currently exist which produce methanol from any of the domestic raw materials mentioned in the previous section. However, this should not be taken to imply that the technology to produce methanol from these other feedstocks is not currently available. Certainly, the synthesis technology is available since it would not differ from that used today. The gasification technology also appears to exist and to be ready for use in commercial scale plants as soon as the decision to build is made. Various coal gasification technologies will be examined below, accompanied by a discussion of the other indirect and direct liquefaction technologies. This discussion will then be followed by brief discussions of the feasibility of producing methanol from other raw materials, such as wood and agricultural and municipal wastes. Finally, a discussion of the relative environmental effects of these production processes will then close out this section.

A. Coal

The gasification of coal began in the early 1800's when it was discovered that coal gas could be burned more efficiently than solid coal and it was cleaner and easier to use. The technology developed fast and by the late 1850's gas lights for streets in London were commonplace. Between 1935 and 1960 there were close to 1,200 municipal "gasworks" serving larger towns and cities in the U.S. However, the introduction of natural gas pipelines in the 1930's initiated the decline and essential disappearance of coal gasification within the U.S. Currently, the only operating large-scale coal gasification facilities are located outside of the U.S. and are used mainly for the production of ammonia, with one large exception. These gasifiers are very similar to the gasifiers used in methanol synthesis since they produce essentially the same medium Btu gas that is required for methanol production. The exception is the largest synfuel facility currently in operation, at Sasol, South Africa, where the Sasol-I and Sasol-II plants gasify about 36,000 tons per day of coal into a medium-Btu gas and from this produce a wide range of products, including gasoline.

Before discussing the individual gasifier types it is first important to examine the properties of coals used in the U.S. There are four properties of coal which are important in the process selection of gasifiers: 1) Reactivity, 2) Ash Fusion Temperature, 3) Free Swelling Index (FSI), and 4) Moisture. Reactivity refers to the coal's ability to catalyze the reaction between carbon and steam. The ash fusion temperature is that temperature at which the ash becomes fluid. FSI is a measure of a coal's tendency to agglomerate or cake when heated; the higher the FSI, the greater the agglomeration.

Eastern coals have relatively poor reactivity due to their low content of alkali metals. These coals (predominantly bituminous) also typically have low fusion temperatures (1990-2200°F), moderate to high FSI, low moisture (4-10 percent by weight as received) and, incidentally, high sulfur (3-5 weight percent). Western coals (mainly subbituminous) exhibit high reactivity and fusion temperatures (2300-2400°F), low FSI, high moisture (28 weight percent) and low sulfur (0.3-0.5 weight percent). Lignite, which is found predominantly in North Dakota, has an even higher moisture content (35 weight percent) and a lower percentage of sulfur (0.2 weight percent).

Coal gasifiers are primarily classifed according to the way coal is fed to them. The three main gasifier categories are the fixed or slow-moving bed, the fluidized bed and the entrained bed gasifiers. Table 3 highlights the advantages and characteristics of the various gasification technologies.

Table 3

Comparison of Gasification Systems[33]

Name	Lurgi	BGC-Lurgi	Winkler	Koppers Totzek	Texaco	Shell-Koppers
Bed Type	Fixed	Fixed	Fluid	Entrained	Entrained	Entrained
Commercial	Yes	Near	Yes	Yes	Near	Near
Coal Flexibility	Western	Western	Western	All	All	All
By-Product	Yes	Yes	No	No	No	No
Efficiency	64	72	57	58	68-72	75
Capacity (STPD Coal)	500	800	1,000	400	1,000	1,000

Fixed or slow-moving bed gasifiers consist of beds that carry or move the coal vertically downward through the zone where it is heated and decomposed (oxygen is injected at the bottom of the gasifier and travels upward as it reacts with the coal). One of the main problems with the updraft fixed-bed gasifier is that the product gas contains large amounts of byproducts including tars, phenols, and methane. These extra products are largely the result of their relatively low operating temperatures. Because of their low temperatures, fixed-bed reactors work best with (and are somewhat limited to) the high reactivity western coals which have high fusion temperatures and low FSIs. The non-caking aspect of western coals is also beneficial to the operation of fixed-bed gasifiers.

As shown in Table 3, the Lurgi and BGC-Lurgi gasifiers are examples of low temperature fixed-bed gasifiers. The Lurgi "dry-ash" fixed bed gasifier is a first generation unit which has been commercially proven and is used worldwide.[33,34] The Sasol-I plant in South Africa which has been operating for over 25 years utilizes the Lurgi gasifier (and also the Fischer-Tropsch synthesis unit) to produce 10,000 barrels per day of fuel. (This is the only fully operational commercial-size coal-liquefaction plant in the world. The Sasol-II plant is operating at 75 percent capacity also using Lurgi gasification and is expected to be fully operationaly soon.[35]) The main disadvantages of the Lurgi gasifier are that it 1) has problems with the low-reactivity eastern coals, 2) produces byproducts, 3) has high steam requirements and 4) has a low capacity per volume of gasifier.

The BGC/Lurgi slagging gasifier is a second generation reactor which completed a testing program in 1979 in Scotland by Lurgi and British Gas Corp with support from 13 U.S. companies and DOE.[36] The slagging gasifier is still being tested by BGC and the latest papers describe this technology as near commercial.[33,34] Its improvements over the older Lurgi dry-ash gasifier are a higher efficiency and a reduction in steam use. However, it still has problems with low-reactivity eastern coals and still produces by-products.

The fluidized-bed reactor accomplishes an efficient contact between gases and solids by blowing gas upward through a bed of solid coal so rapidly that the suspended bed churns as if it were a fluid. Fluidized-bed gasifiers have higher, more uniform temperatures which tend to reduce the amount of byproducts produced, but the higher velocity of the gas tends to carry out ash and char with it that must be removed later. Since the typical temperature is low with respect to the ash melting temperature of coals, the fluid-bed gasifier also has problems with eastern coals. The Winkler fluid-bed gasifier is a first generation unit which is commercially proven and used around the world.[33] According to DM International over 70 Winkler gasifiers have been built.[16] The two main disadvantages with the Winkler are that it operates at atmospheric pressure (large volume per throughput) and that it has a tendency to clog when using eastern coals. A pressurized modification of the Winkler is now under development which should improve its efficiency.[16]

In an entrained-bed gasifier fine particles of coal are suspended in a stream of oxygen which moves rapidly into and through the decomposition zone. Since entrained bed gasifiers are typically operated at temperatures above the melting point of coal ash, reaction rates are much faster, allowing many of the undesirable byproducts associated with fixed and fluid-bed systems to be destroyed. These gasifiers are also called "slagging" because they remove the ash in a molten, slag form. One of the big advantages of entrained bed gasifiers is that they can utilize any type of coal. As shown in Table 3, Koppers-Totzek, Texaco and Shell-Koppers are all entrained bed gasifiers.

The Koppers-Totzek gasifier is a first generation technology which, like the Winkler and Lurgi, has had extensive commercial experience.[33,34]. It will handle all types of coal but does require large raw gas compressors since it operates at atmospheric pressure.

The Texaco gasifier is a coal-slurry fed, high-capacity gasifier which handles all types of coals and produces very little byproduct. Although the Texaco gasifier has not yet been used on a commercial scale it has been successfully tested in two large demonstration plants (165 tons of coal per day).[37] Of the newer, second-generation technologies Texaco appears to be leading the race to commercialization, as it is currently planned for utilization in two new commercial plants which are now under construction: Tennessee Eastman's project to produce acetic anhydride and other chemicals from methanol made from coal, and Southern California's Cool-Water power generation station near Barstow, California.[34]

The Shell-Koppers gasifier is very similar to the Texaco gasifier in that it can also use any coal and produces very little byproduct. Shell is currently designing two prototype plants to be built in Europe which are scheduled for commissioning in 1985 or 1986.[38]

Until recently, industry has been slow to reimplement coal gasifiers in the U.S. However, the increasing cost of natural gas has sparked a new interest in coal gasification and the majority of the coal or shale-based synthetic fuel projects currently being planned use coal gasification.[14]

One example is the previously-mentioned Cool Water combined-cycle power-generation demonstration plant, to be located in Barstow, California. It will gasify 1000 tons per day of coal to produce 100 MW of electricity. The facility, which uses the "proven" Texaco Coal Gasification Process, was to begin construction in July 1981 and be ready for start-up before the end of 1983,[39] but has been delayed due to a lack of necessary financing.[40] The project still appears to be a viable one, however, as new sources of capital are appearing and the key step appears to be obtaining $75 million from the Synthetic Fuels Corporation.[40]

According to a recent study by GAO (July 1980), methanol from coal technology has also been available for years.[21] Prior to the availability of relatively inexpensive natural gas as a methanol feedstock, France produced methanol from coal in the late 1940's, and in the mid-1950's, the Dupont Chemical Company operated a methanol from coal plant in the United States. A methanol from coal conversion plant, located in a suburb of Johannesburg, South Africa, has been in operation since 1974. As a smaller part of a larger coal to ammonia chemical plant, this process utilizes Koppers-Totzek gasification technology and the ICI synthesis process, and puts out about 90 metric tons of methanol per day.

It should be noted, however, that previous foreign coal methanol facilities produced methanol for chemicals, not fuel purposes. New methanol fuel plants would be much larger than any previous chemical plants, perhaps up to 100 times greater in scale. Therefore, previous operating experience with methanol chemical plants may not be totally applicable to new methanol fuel facilities.

Concerning methanol synthesis in the U.S., industry officials have told GAO that a commercial-sized methanol-from-coal plant could, with existing technology, will be in operation within 5 years.[21] Presently, W. R. Grace is in the final stages of a feasibility study for a 500-700 ton per day methanol-from-coal plant that would be on line by 1985-86.[14] They had originally planned to build a 5,000 ton per day methanol plant, but could not ascertain that there would be enough demand for the methanol. In addition, DM International has completed designs for a large-size lignite-to-methanol plant and are prepared to provide commercial guarantees of the plant's technical and process workings.[22] Table 4 shows a list of 9 methanol projects in which the production of methanol is tentatively planned to be on stream by 1987 or sooner. The planned facilities are well distributed across the country, representing over 8 different states, while utilizing a wide range of coal types, from eastern bituminous to lignite and peat. The first two plants are already under construction, although the Great Plains project is more oriented toward substitute natural gas (SNG) and the Tennessee project only produces methanol as an intermediate product. While there is much doubt that many of the planned projects will ever be able to

Table 4

Coal to Methanol Projects

Project Name	Plant Size (Barrels Methanol/day)	Construction Date	On Stream Date
1. Great Plains Coal Gasification Project Mercer County, ND	125	July 1981	1984
2. Coal-to-Methanol-to-Acetic Anhydride Tennessee Eastman Kingsport, TN	4,200	1980	1983
3. *Beluga Methanol Project, Granite Point, AK	54,000	N/A***	N/A
4. Grants Project **(ETCO), Grants, NM	3,608	N/A	N/A
5. Mapco Synfuels Carmi, IL	35,000	N/A	N/A
6. Peat-to-Methanol **(ETCO), Creswell, NC	3,714	N/A	N/A
7. Keystone Project Cambria and Somerset Counties, PA	100,000	N/A	N/A
8. Dunn Nokota[18]**** Lignite-to-Methanol Dunn County, ND	40,000 40,000	1985 1988	1989 1991
9. Chokecherry **(ETCO), Moffat County, CO	3,608	N/A	N/A

Source: EPA, April 1981.[14]

* Feedstock is 60 percent natural gas, 40 percent coal.
** Energy Transition Corporation (ETCO).
*** Firm dates not available.
**** Two-stage construction with a final capacity of 80,000 BPD.

obtain the necessary financial backing without government guarantees, there appears to be less doubt of these projects' technical feasibility. Thus, with the confirmation of a currently operating coal-to-methanol plant in South Africa and the number of coal-to-methanol facilities under construction or planned, there appears to be little doubt that coal-to-methanol technology is ready for implementation in the U.S.

The observations made above concerning the production of methanol also apply to the Mobil MTG process since it produces gasoline from methanol.[33] After its production by indirect liquefaction, methanol is catalytically converted into a mixture of gasoline (roughly 85 percent) and liquified petroleum gas (LPG) (15 percent) in either a fixed-bed or fluidized-bed reactor.

The MTG process has been demonstrated in both reactor types by 4 barrel per day pilot plants.[41,42] The fluidized-bed approach offers advantages of superior heat transfer and somewhat higher gasoline selectivity than the fixed-bed process, but requires more extensive scale-up and engineering development efforts based on accomplishments to date.[41,43] A four-year plan to construct and operate a 100 barrel per day fluidized-bed unit has been proposed to demonstrate scale-up and to provide additional data for commercial design.[41]

Currently, the fixed-bed design is receiving primary commercial attention as the New Zealand government has tentatively selected this process to provide about one-third of that country's gasoline needs.[42] This MTG plant would be a 13,000 barrel per day facility and use off-shore natural gas to produce the methanol.[42] This would be the first commercial application of the Mobil MTG process.

Now that the technolgical feasibility of the indirect liquefaction processes have been examined, the next step will be to examine the direct liquefaction process. Three direct-liquefaction processes will be examined here, the Exxon Donor Solvent (EDS) process, the H-Coal process, and the Solvent-Refined Coal-II (SRC-II) process. These are the processes that have been receiving the most attention and the most government support.

The H-Coal process is a development of Hydrocarbon Research, Inc. (HRI). The central sections of the process have been thoroughly tested on bench scale and process development units (PDU). This work was initiated over 16 years ago and has continued until now through funding arrangements with government and industry. As a result, more than 65,000 hours of data at the bench scale level and more than 14,000 hours of data for 3 ton per day PDU are available.[44]

A large-scale pilot plant has been constructed at Catlettsburg, Kentucky, that is designed to process 200 to 600 tons per day of coal to produce from 600 to 1,800 barrels per day of liquid product.[44,45] Ashland Oil is responsible for the operation of the plant, which uses commercial size equipment. Starting in February, 1980, the pilot plant was "broken in" by various petroleum liquid feeds, starting with light gas and working toward residual fuel oil to eliminate any deficiencies in the operating equipment and to provide operator training. Starting on May 29, 1980, the plant was operated intermittently in the syncrude mode on Kentucky #11 coal, at a feed of about 220 tons per day. Only intermittent operation was achieved due to mechanical problems.[44,45]

In February, 1981, the pilot plant was switched to Illinois #6 coal. Uninterupted operation of 45 days was achieved.[44] The overall amount of coal processed during this period was 8,500 tons or 85 percent of the 220 tons per day design rate characteristic of syncrude mode operation on Illinois #6 coal. Illinois #6 coal was reintroduced on April 26 for more investigation.[44]

Many maintenance problems were encountered during these initial starting periods. High temperature, erosive wear, breakage of components, and other mechanical difficulties have plagued much of the operations. Most of these problems hve been corrected, however.[44]

Plans for a commercial plant began in April, 1980, by a cooperative agreement with Ashland, Airco and the Department of Energy.[44] This plant is to be located in Breckinridge County, Kentucky, and will be designed to convert about 23,000 tons per day of Illinois #6 coal into 50,000 barrels per day of liquid hydrocarbon products and about 30 thousand standard cubic feet per day of SNG. The commerical plant is approximately 100 times the size of the pilot plant. However, the H-Coal commerical plant would have several reactors in parallel, depending on the economy of scale desired by the operator and the availability of capital. In terms of the individual reactor train, the commercial-scale reactor would have about ten times the throughput of the Catlettsburg pilot plant with a diameter scale up of about a factor of three.

Construction of the commercial plant is projected to begin in 1983.[46] By 1988, construction should be completed followed by efforts for plant startup. In 1991, the plant is projected to be operating at full capacity. All of this, of course, depends on successful operation of the pilot plant now in operation and the availability of financing, including government support.

The EDS process was developed by Exxon as a private venture from 1966 until 1976.[47] During this time, Exxon developed and demonstrated the primary liquefaction process in laboratory scale reactors up to 1 ton per day of coal. In July 1977, ERDA (now DOE) agreed to fund 50 percent of a project to design and construct a $268 million 250 ton per day pilot plant. Construction of this pilot plant in Baytown, Texas, was completed in March, 1980, and is being followed by a thirty month operational program.

Engineering design and technology studies, bench scale research and small pilot unit operation are being integrated to support operation of the 250 ton per day coal liquefaction pilot plant.[47] Work is also in progress to evaluate the use of a bottoms partial oxidation unit for the generation of hydrogen or fuel gas.

Sixteen process goals were established for the first four months of operation of which eleven were reached. The goals reached included operation on 8 mesh coal, demonstration of the ability to dry coal to 4 percent moisture, achievement of a 50 percent on-stream factor, and several fractionation section objectives. The original goals not reached include steady operations at conditions near the design coal feed rate and a 1.2:1 solvent-to-coal ratio, operation of the reactor solids withdrawal system, and operation of the slurry drier.[47]

During the first four months of operation the problems experienced by the plant were primarily mechanical rather than process oriented. The mechanical problems included erosion of the vacuum tower transfer line, breakdown of the solids handling systems and plugging of the slurry heat exchangers. The key to sucessful operations was avoiding solidification of heavy materials and solids plugging. The service factor was strongly dependent upon the time required to unplug the equipment after a coal outage due to solidification-based plugging.[47]

A preliminary observation indicated a lower plant efficiency than expected. This observation has not been resolved. However, it should be mentioned that the efficiency of the EDS that will be stated below was that expected prior to the operation of the pilot plant and used in Exxon's latest commercial plant design.[48] If the lower efficiency seen at this time in the pilot plant is not improved in future operations, then the projected efficiency of a commercial EDS plant would also have to be lowered.

According to Exxon's commercialization estimates, after operation of the 250 ton per day pilot plant in the 1980-1982 time frame, a design basis for an EDS demonstration plant could be available in 1982.[49] With a three year design and construction period, construction of the demonstration plant could begin in 1985 and be completed in 1988 or 1989.[49] The 13,000 ton per day demonstration plant would be equivalent to one train of a 25,000 ton per day commercial plant. Each train would include two identical liquefaction lines. Therefore the commercial plant would have four liquefaction lines processing 6,250 tons of coal per day per line. The scale-up factor from the 250 tons per day pilot plant to the demonstration plant would be twenty-five. Design of a commercial plant could begin after the demonstration plant was in operation for one year.[49] This would mean beginning the design in 1989 and construction in 1992. Therefore Exxon projects that 1997 would be the earliest possible start-up date for a commercial plant.[49]

The Pittsburg and Midway Coal Mining Co. (P & M), a wholly owned subsidiary of Gulf Oil Corp., has been working on the development of the SRC-II technology for 18 years, primarily under the sponsorship of DOE. During the last four years, a 30 ton per day pilot plant has been in operation at Fort Lewis, Washington. Following the pilot plant operation, a 6000 ton per day demonstration plant was to be built and operated near Morgantown, West Virginia using high-sulfur West Virginia and other bituminous coals.[50]

Initial work on the demonstration plant contract involved developing a preliminary design for the 6000 tons per day demonstration plant, a conceptual design for a 30,000 tons per day commercial plant based on an expansion of the demonstration plant, and a conceptual design for a 30,000 tons per day grass-roots commercial plant. All of this work was completed in what was known as Phrase Zero of the demonstration plant project in July, 1979. Phase One of the demonstration plant project, which is in progress, was started in July 1979.[50]

In the Phase One design, the SRC-II process has been based on the results from: 1) bench-scale laboratory units at the Merrian Laboratory, 2) a 1 ton per day process development unit at the Harmarville Research Laboratory and, 3) the 30 ton per day pilot plant at Fort Lewis, Washington. The Phase One design is also based on a specific West Virginia coal rather than the hypothetical coal used for the Phase Zero design.

Some key features of the demonstration plant that were to be tested are: dissolving; efficient cooling and separation at higher temperatures; handling and pumping of hot vacuum bottoms to high pressure; mixing and pumping of hot slurries at the incipient gel stage; and operation of the slurry preheater at flow rate and heat flex comparable to the demonstration plant design.

Projections of the main product slate of the demonstration plant include pipeline gas (SNG), liquid propane, naptha, and fuel oil. Excess synthesis gas (above that required for reactant hydrogen) would be used as plant fuel. The pipeline gas, propane, by-product sulfur and ammonia will be produced to industry specifications and marketed accordingly.

The United States, West Germany, and Japan were responsible for financing this demonstration plant. Pittsburg and Midway Coal Mining was responsible for development of the plant under DOE supervision. Latest estimates show that the design (Phase I) of this plant, which began in October, 1979, was to be completed in July, 1984.[51] Phase II, or construction of the plant, was the start in June, 1981, and to be completed in September, 1985. Phase III, or the operation of the plant, was to begin in July, 1986 and end in June, 1988. However, recently the U.S., West Germany, and Japan agreed at a meeting in Bonn to terminate all phases of the SRC-II process as soon as possible.[52] This decision was made primarily because of the cost involved and because of the U.S. position that synthetic fuel development is primarily the responsibility of the private sector. The future of this process is therefore unknown, since it now appears to rest with the private sector, which has not yet made public any plans.

Overall, then it can be seen that the technological feasibility of the various processes differ to a fair degree. Methanol processes are technologically feasible and available, though the most efficient, second generation gasifiers have yet to be fully commercialized, but will soon be in some cases. The MTG process is only a step behind, though it is an important step. The actual start of construction on the New Zealand plant will be a key show of confidence and its successful operation will be an important demonstration, though this is some years away. The direct liquefaction processes are even further away from commercial feasibility. Since DOE recently withdrew funding for the EDS and H-Coal pilot plants, the fate of these two projects, in addition to the above mentioned SRC-II, appears to be in the private sector. The pilot plant results will be of utmost importance in establishing confidence in the projected costs and efficiencies which are needed to provide capital for commercialization.

Now that the technological feasibility (and commercialization status) of the various coal conversion technologies has been discussed, the next step will be to examine the thermodynamic conversion efficiencies and the product mixes of these same technologies. The information presented has been taken from the most recent sources which were available to the public. The actual efficiencies presented may differ somewhat from those found in the original source documents as an effort was made to put all of the efficiencies on the same, and most comparable, basis. For example, all off-site use of power was included as energy input, not only as kilowatt-hours of electricity, but as Btu of coal required by a typical power plant to generate that electricity.[48] Also the inefficiency of any refining of the fuel that would be required to meet standard petroluem product specifications was also included as was appropriate in each process. The energy content of byproducts was excluded to place more emphasis on useable fuels and to de-emphasize the production of byproducts such as sulfur. In reality, this last adjustment has little relative effect since all the processes examined produce a small amount of byproduct.

The efficiencies and product mixes of the various processes are summarized in Table 5. As can be seen, the efficiencies of two methanol processes are presented. As described above, there are many types of gasifiers and each has its own efficiency. There are also a number of methanol synthesis processes, such as the ICI low-pressure, the Lurgi low-pressure, and the Chem Systems liquid-phase processes. The first two are fully commercial, gas phase processes. The latter is a new process which has not been demonstrated on a large scale as of yet.[53] However, the efficiencies of the synthesis processes are close to one another and the differences in gasifier technology dominate the differences in overall process efficiencies.

The two efficiencies shown for methanol represent the range of efficiencies expected for nine different gasifier/synthesis combinations for which designs were available.[7,10,16,54,55,56,57,58] The Koppers-Totzek gasifier (49.3) percent) is commercially available and represents the lowest efficiency of these gasifiers. The "slag-bath" gasifier shown is a second-generation gasifier and represents the best efficiency of this group of gasifiers.

In all cases, the process designs mentioned called for the sole production of methanol as a product. Only such processes were presented to emphasize that the problem being addressed by this paper is a liquid, transportation fuels problem and not simply an energy problem. The efficiency of producing methanol can be improved to 67 percent by co-producing substitute natural gas (SNG).[10] Since this improvement occurs in the gasifier/synthesis-gas purification portion of the plant, it applies in a similar fashion to other indirect liquefaction processes such as the Mobil MTG and F-T processes. Using the results of the Mobil study, it would be more economical to co-produce SNG if it could be sold for 50 percent of the energy value of the methanol or MTG gasoline.[10] If in the future SNG will be able to demand that price or more in the market place (which should be fairly likely), then methanol will be able to be made more efficiently than that shown in Table 5 and more economically than when produced as the sole product (see Section V).

The other indirect liquefaction technology presented in Table 5 is the Mobil MTG process. Since Mobil MTG produces gasoline (and some liquified petroleum gas (LPG)) from methanol, its efficiency must be less than that of producing methanol. Mobil estimates that the thermal efficiency of its fixed-bed reactor technology is 86.7 percent.[10] Adding this to the efficiencies

Table 5

Process Efficiencies and Product Mix of Various Coal Liquefaction Processes

Process	Conversion Efficiency	Product Mix (Energy Basis)
Crude Petroleum	92%	50% Gasoline 33% Distillate 15% Residual 2% LPG
Indirect Liquefaction		
Modified Lurgi Gasification Lurgi Synthesis	57.3%	100% MeOH*
Koppers Totzek gasification ICI Synthesis	49.3%	100% MeOH*
Mobil MTG - Fixed Bed - Fluidized Bed	43-50% 45-53%	88% Gasoline 12% LPG
Direct Liquefaction**		
Exxon Donor Solvent (EDS)	55.8%	32.7% Reg. Gasoline 14.0% Prem. Gasoline 25.6% No. 2 Fuel Oil 9.6% LPG 18.1% SNG
H-Coal	61.8%	33.1% Reg. Gasoline 11.2% Prem. Gasoline 20.4% No. 2 Fuel Oil 22.3% LPG 13.0% SNG
Solvent Refined Coal (SRC) II	63.6%	64.7% Gasoline 12.1% LPG 23.2% SNG

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* MeOH = 95-98% methanol, 1-3% water and the remainder higher alcohols.

** These efficiencies include the effect of refining where needed. However, the refinery product slates are not identical for each of the direct liquefaction processes.

shown in Table 5 for methanol results in the 43-50 percent range of efficiencies shown in Table 5.

Mobil has also been developing a fluidized-bed reactor which is projected to increase the efficiency of its MTG process to 91.7 percent. However, as mentioned earlier, the fluidized-bed reactor is further from commercialization and its efficiency is more of a projection than the value for the fixed-bed reactor. Overall, with this reactor, the MTG process is 45-53 percent efficient.

The Mobil MTG product is primarily high-octane (83 MON, 93 RON, unleaded) gasoline (roughly 85 percent) with the remainder being LPG.[10] This is an excellent product mix from a transportation point of view. The one possible drawback in the area of product quality would be the presence of a considerable amount of durene in the gasoline (3-6 percent).[59] Durene is a relatively large molecule (C-10 adkyl-benzene) and has a freezing point of 175°F. Tests by Mobil have shown some driveability problems (fuel crystalization in carburetor) under certain conditions at durene levels of 5 percent, but the effects at 4 percent were only minimal. Two solutions are possible. One, the catalyst may be able to be modified to reduce the amount of durene produced. Or two, MTG gasoline could be blended with petroleum-derived gasoline to reduce durene to acceptable levels.

To obtain the overall efficiencies for the direct liquefaction technologies, estimates for the efficiencies of the direct liquefaction plants and the efficiencies of the coal syncrude refineries (processing only the C_5+ liquefaction product) are necessary. The efficiencies of the direct liquefaction plants are available from the latest design projections made by Exxon (EDS), P&M (SRC-II) and HRI (H-Coal). However, refinery efficiencies were not directly available in each case. In the following paragraphs, refinery efficiencies will be discussed. Then direct liquefaction efficiency and overall process efficiencies will be presented.

One refining study has been performed by Chevron on the refining of the SRC-II syncrude.[59] This study was based on laboratory data along with general petroleum processing correlations obtained from refineries constructed by Chevron. A less detailed study was performed by UOP on the refining of the H-Coal syncrude.[60] This study used linear programming techniques based on UOP's experience with refining and their knowledge of the H-Coal syncrude. A detailed study on the refining of EDS crude has not yet been performed.

The Chevron/SRC-II refinery was designed to produce 100 percent gasoline. An analysis of this refinery indicated a thermal efficiency of 83 percent. An analysis of the UOP/H-Coal refinery indicated a thermal efficiency of 95 percent. This refinery was designed to meet a gasoline/distillate ratio of 2.0.

Modern petroleum refineries which use heat-recovery devices and up-to-date technology have thermal efficiencies of about 92 percent.[61] Since the H-Coal, EDS, and SRC-II syncrudes are hydrogen deficient and high in nitrogen and oxygen relative to petroleum, and their refining would require more hydrogen per barrel, it would appear unlikely that the refining of the coal syncrudes would be more efficient than the refining of petroleum. Since the Chevron/SRC-II refinery produces 100 percent gasoline, which requires high-severity refining, its thermal efficiency of 83 percent is reasonable, and will be used in this report for the SRC-II process. However, the H-Coal refining efficiency is higher than the 92 percent petroleum refining efficiency. One answer for this could be that a grass roots H-Coal refinery does not require vacuum bottoms processing because of the properties of the H-Coal syncrude feedstock. However, atmospheric processing for the H-Coal syncrude would still be much more severe than that for petroleum processing because of the syncrude's hydrogen deficiency and high nitrogen and oxygen content. Another reason for the high thermal efficiency of the H-Coal case might be that UOP did not focus their attention on efficiency since neither efficencies nor heating values of feedstocks and products are included in their report. It appears reasonable, then, to reduce the efficiency of the H-Coal refinery to 0.92, the same as that for a modern petroleum refinery.

Since there has not been any detailed refining study for the EDS syncrude, a representative efficiency will be estimated. The quality of the EDS syncrude is a bit poorer than that of the H-Coal crude since the EDS syncrude has a lower hydrogen content and higher nitrogen and oxygen contents (see Table 6).[48,60] The theoretical hydrogen requirement necessary to bring the hydrogen, nitrogen, oxygen, and sulfur levels of the EDS crude up to the quality of the H-Coal oil is 248 standard cubic feet (scf) per barrel of the EDS crude. That for SRC-II syncrude is 469 scf per barrel.[59,60] Of course, during actual refining the amount of hydrogen would be greater since this theoretical level could not be attained. Therefore, the thermal efficiency for refining the EDS syncrude would be lower than that of the H-Coal crude given identical product slates, but about the same amount above that of the SRC-II refinery given its product slate. Therefore, the thermal efficiency chosen for EDS syncrude refining will be 88 percent, a rough mean between the two available values.

It should be noted, however, that even if these refining efficiencies are off by 2-3 percent, the effect on the overall direct liquefaction efficiencies will be less than 1-2 percent. Also, these efficiencies take into consideration hydrogen from naptha reformation.

Before the overall direct liquefaction efficiencies are determined, the efficiencies and the product slates from the direct liquefaction processes will be presented. Based on the

Table 6

Refinery Feedstock Property Data

	H-Coal[13]*	SRC-II[11]**	EDS***
Specific Gravity	0.8733	0.9427	0.928
Gravity, °API	30.5	18.6	21.0
Total Nitrogen, Wt-%	0.37	0.85	0.48
Oxygen, Wt-%	1.72	3.79	1.75
Sulfur, Wt-%	0.15	0.29	0.479
Carbon, Wt-%	86.7	84.61	86.73
Hydrogen, Wt-%	11.0	10.46	10.56
Ramsbottom Carbon, Wt-%	-	0.70	-
Conradson Carbon Residue, Wt-%	0.10	-	-
Benzene Insolubles, Wt-%	-	0.03	-
C_7 Insolubles, Wt-%	0.10	-	-
Ash, ppm	67	40	-
Bromine Number	41.7	70	-
Pour Point, °F	-	-80	-
Viscosity, CS at 100°F	-	2.196	-
ASTM D 86/D 1160 Distillation, °F at Vol-% Distilled:			
Start/5	-	154/217°F	-
10/30	-	281/382	-
50	-	438	-
70/90	-	484/597	-
95/End Pt.	-	699/850	-
Distillation, °F vs. Vol-% Distilled			
13.87 Vol-%	C_4/C_6	-	-
30.84	C_6/350°F	-	-
10.4	350/399	-	-
40.89	399/650	-	-
3.99	650/880	-	-

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* Derived from Burining Star Mine, Illinois No. 6 coal.
** Derived from Blacksville No. 2 Mine, Pittsburgh Seam coal.

*** Derived from Monterrey, Illinois No. 6 coal.

latest available projections, the efficiencies of the EDS, H-Coal, and SRC-II processes are 61.6, 63.1 and 72 percent, respectively.[48,62,63,64] The actual product slates from the direct liquefaction processes before refining are presented in Table 7 as a percentage of total energy. A breakdown of the refinery feedstocks are also presented in this table.

Now that the refinery and direct liquefaction efficiencies have been determined, the overall thermal efficiencies and product slates for the direct liquefaction technologies may be obtained. These are shown in Table 5. Note that not all of the products from direct liquefaction need refining and therefore the refining efficiency penalty is only applied to those products needing refining. As can be seen, the indicated conversion efficiency for the EDS process is 55.8 percent, in the upper-middle of the range of methanol efficiencies. This figure is based on Exxon's latest projection of EDS efficiency[48] and an average refining efficiency of 88 percent for those products requiring refinement. As mentioned earlier, the EDS process efficiency is based on projections made in 1978 (design published in March, 1981) prior to operation of their pilot plant in 1980 when their latest design study was begun.[48] The latest information on their pilot plant operation indicates that it is not attaining this projected efficiency.[47] At this time it is not known whether this is correctable or whether it is an indication of a true lower process efficiency. In their latest estimate, Exxon had already lowered the projected efficiency of the liquefaction process significantly from their estimates made in 1975 (design published in 1978) based on development work between 1975 and 1978.[48] However, they were able to retain the overall process efficiently by improving their processing of the vacuum bottoms produced in the process.[48]

The efficiency of the H-Coal and SRC-II processes were also taken from the latest available projections.[62,63,64] The overall efficiency of the H-Coal case is 61.8 percent. This is based on an average efficiency obtained from the high and low estimates reported by Fluor Corp. for the liquefaction section,[63] and a 92 percent efficiency for the refinery.[59] The overall efficiency for the SRC-II case is similarly 63.6 percent.[60,62] As was the case with the EDS process, the H-Coal estimate has not been confirmed by pilot plant operation, but estimates of the pilot plant efficiency should be available in the near future. The estimate of the SRC-II efficiency has also not been confirmed by pilot plant operation of the scale now being undertaken by Exxon and HRI (250-600 tons of coal per day). Pittsburg and Midway Coal Mining have been operating a 30 ton per day plant for a number of years, as mentioned earlier, and it is likely that the SRC-II efficiency estimate was based on at least some data from this plant.

The overall product mixes for the three liquefaction processes are also shown in Table 5. The overall product mix is

Table 7

Products from Direct Liquefaction and Feedstocks to Refinery as a Percentage of Total Energy*

	Liquefaction Products			Refinery Feedstock		
	H-Coal	EDS	SRC-II	H-Coal	EDS	SRC-II
Naptha	29.2	34.6	18.9	32.2	35.5	21.6
Fuel Oil No. 2	38.8	33.7	63.3	42.7	34.7	72.31
Distillate/ Boiler Fuel	22.8	28.9	5.3	25.0	29.7	6.1
LPG	--	2.8	--			
Butane	5.8	--	0.1			
Propane/Ethane	3.5	--	2.0			
Methane	--	--	10.3			

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* Note that not all products from direct liquefaction need refining and therefore the refining efficiency penalty is only applied to these products which do.

based on finished products being produced by the refinery and the liquefaction plant. Finished product output from the liquefaction plant includes only LPG, SNG, and some finished gasoline being produced in the H-Coal case. The remainder of the output from the liquefaction plants are the raw coal syncrudes which are sent to the refineries. The Chevron/SRC-II refinery produces 100 percent gasoline, while the H-Coal and EDS cases are designed to meet a gasoline/distillate ratio of 2.0. Therefore, these overall product slates for the direct liquefaction technologies contain a large portion of transportation fuels. The overall percentage of gasoline produced for the three processes ranges from 44 to 65 percent. LPG may also be used as a transportation fuel in a retrofitted gasoline engine. The percentage of LPG produced by the processes ranges from about 10 to 22 percent. However, the distillate produced by these processes will probably not be available for use as diesel fuel. Coal liquefaction distillates need to be severely hydrotreated to reduce the aromatic content to a sufficient degree (less than 25 percent aromatics) so that a cetane number of 36-39 can be obtained.[62,65] These cetane numbers are still lower than the minimum ASTM specification of 40,[66] and well below the current national average of 46.[67] Therefore, additives to boost the cetane number would be required before even severely hydrotreated coal distillate could be used as diesel fuel. This would be more severe hydrotreatment than indicated in Table 5 and would lower the indicated efficiencies and yields.

The relatively high levels of SNG from the EDS and SRC II processes also make a plant co-producing SNG and methanol or SNG and gasoline (MTG) more reasonable. While we believe that transportation fuels are needed the most from the U.S. synthetic fuel industry, it is also appropriate to compare processes on equal bases. It may be more appropriate to compare these direct liquefaction processes with methanol and MTG gasoline plants co-producing some SNG than to plants producing 100 percent methanol or gasoline.

B. Wood

Methanol from wood was first produced by pyrolysis as a minor by-product of charcoal manufacturing. However, this process is no longer economical. The most efficient way to produce methanol from wood today is in the same manner that it is produced from coal, which has already been described. According to the Solar Energy Research Institute (SERI), wood has a number of advantages over coal in terms of conversion to methanol: 1) wood is easier to gasify than coal, 2) it contains its own oxygen and water, 3) its ash content is less than 2 percent, and 4) its sulfur content is less than 0.1 percent (compared to 2-4 percent in coal).[68] Unfortunately, these advantages are somewhat offset by: 1) the need to dry the wood to the correct moisture content, 2) wood's low energy density, and 3) the lack of large concentrations of wood, thus requiring smaller, higher cost methanol plants.[68]

One proposed solution to these problems is wood densification. According to SERI, densification of wood refuse into pellets ("instant coal") would require only 1-2 percent of the total energy contained in the wood.[68] In addition to reducing transportation costs and being a superior feedstock, these pellets can also be dried more efficiently by using the gas fuel they produce. In fact the drying energy is largely recovered in the more efficient gasification of the pellets. However, the economics of densification are likely to vary and may not be profitable in all situations. It has also not been demonstrated on a large scale.

Wood gasification originally started around the early 1800's and by the time of World War II (during petroleum shortages) there were almost a million small gasifiers being used to run cars, trucks, and buses primarily on wood. Although the attention on gasification has since been focused on natural gas, and then coal, there is a large amount of research presently being done on wood gasification. According to DM International (formerly Davy Powergas, Inc.), which has designed 60-65 percent of the installed capacity currently producing methanol from natural gas, the technology to gasify wood for methanol production exists, but gasifiers have not yet been optimized for wood utilization.[69] DMI is currently in the process of designing a 2,000 ton per day methanol plant for use in Brazil which is based on wood gasification.

Although conventional fuels can also be made directly from wood, most of this technology is still in the development stage.[26] For instance, pyrolytic oil can be produced by slowly heating pressurized biomass (direct liquefaction) while olefins can be made by fast heating or flash pyrolysis (indirect liquefaction).[26] Presently, research is being conducted with pyrolysis and some day these processes may be proven and profitable. Genetic engineering efforts are also addressing the conversion of wood into more useful products and this may hold some promise for the future. However at this time there appear to be no gasoline or diesel fuel precursors that can be economically produced from wood.[26]

C. Agriculture and Municipal Wastes

Like coal and wood, the technology to gasify agricultural and municipal solid wastes (MSW) is for the most part proven, though gasifiers must be optimized to run on these fuels. In fact, a 200 ton per day MSW gasification facility designed by Union Carbide Corporation is currently operating in South Charlestown, West Virginia.[68] DOE has estimated that the conversion efficiency for agricultural residues may be as high as the 58 percent quoted for wood, while Stanford Reseach Institute claims a 46 percent conversion efficiency for MSW.[27,30] One of the biggest challenges with gasifying MSW is simply keeping slag (unburnables) and gaseous impurities down as low as possible, since the MSW raw material is far from uniform and contains metal, glass, etc.

D. Environmental Effects

The previous discussions have described the availability of the various technologies that produce both methanol and synthetic gasoline from coal and other raw materials. These processes will all affect the environment to some extent, as will the distribution and storage of the fuels themselves. In this section, some of the environmental effects will be examined, particularly when one process or fuel may have relative advantages or disadvantages. The emphasis will be placed on coal-based processes and fuels. The production of methanol from wood or peat may be inherently safer environmentally than the production of any fuel from coal, since the raw material will contain very little sulfur and lower amounts of most heavy metals (mercury being the most notable exception). Thus, very little needs to be said about these processes. Of course, this assumes that proper care is taken in harvesting the wood or digging the peat. Improper harvesting or overharvesting of wood can deplete forests and damage ecosystems, harming wildlife, recreation and agricultural activities. Similarly, the harvesting of peat can damage the ecosystem. In addition, improper wood gasification could release potentially harmful organic substances into the air similar to the gasification or liquefaction of coal.

The environmental analysis of production and distribution of synthetic liquid fuel from coal is not intended to be a complete analysis and is largely qualitative, rather than quantitative. The necessary scientific data do not yet exist for such a complete analysis to be possible.

In addition to discussing environmental problems common to both indirect and direct liquefaction technologies, this analysis also examines the theoretical environmental advantages and disadvantages of indirect liquefaction (relative to direct liquefaction) during production. It also reviews current scientific literature on the environmental effects during end-use (the latter is done in Section IV). In general, more environmental data are available on the end-use of pure methanol fuels, than on the production of methanol. It should be noted, however, that current data on using pure methanol fuel are based on methanol produced from natural gas. Coal-based methanol may contain more impurities than methanol from natural gas. These impurities could potentially cause additional environmental effects. Any such impurities, however, should be present in very small quantities because it is necessary to purify the feed-gas to the methanol synthesis catalyst.

Coal itself contains many elements and compounds in addition to hydrogen and carbon, such as organic nitrogen-containing compounds, organic and inorganic sulfur, and trace metals, such as lead, arsenic, etc. The conversion of coal to other fuels offers a number of opportunities for these pollutants to reach the environment in harmful ways, regardless of the particular conversion process used.

The Federal Interagency Committee on the Health and Environmental Effects of Energy Technologies has attempted to identify potential adverse effects of coal gasification and liquefaction technologies.[70] The committee focused on such issues as water quantity, direct aquatic discharges of organics, inorganics, and trace elements, airborne contaminants and their impact on water quality, and solid waste. The highlights of its findings and pertinent points by other reseachers are discussed below.

The availability of water for coal conversion technolgies may be a problem in both the eastern and western regions of the U.S. However, since many western regions receive one fourth or less as much surface precipitation as regions in the east, water availability is inherently a greater problem there. Also, seasonal fluctuations of stream flow are greater in the west. In order to evaluate the impact of coal conversion technologies on water supply, the committee identified a need to quantify the amount of water available both as surface and ground water during an average year and during periods of low precipitation. Also, instream flow requirements need to be established to protect aquatic biota. It should be noted that a closed-loop, or "zero discharge," aqueous stream approach appears possible for coal conversion technologies. This system would greatly reduce water requirements as well as limit direct aquatic pollution (discussed below).

The aqueous discharge of trace organics may present an environmental problem, especially since several of the organic substances anticipated to be generated by coal conversion facilities are known carcinogens.[70] The Interagency Committee further anticipates that organics could be released at levels which may be toxic to aquatic life. The transport and transformations of trace organics need to be determined, however, before the extent of potential adverse effects can be quantified. Inorganic substances such as ammonia, cyanide, and thiocyanate were also identified as potential toxic agents to aquatic organisms.

One potential advantage of gasification over direct liquefaction is the fact that most of the organic nitrogen and sulfur is broken down to simple compounds like ammonia and hydrogen sulfide. These are relatively easy to separate from the carbon monoxide and hydrogen which make up the major part of the synthesis gas. Also, since the carbon monoxide and hydrogen entering the methanol synthesis unit must be essentially free of sulfur to prevent rapid catalyst deactivation, there is an economic necessity for its removal.

Coal liquefaction, on the other hand, inherently leaves some of the sulfur and nitrogen in the liquid phase, bound with the organics. The most effective technique to remove these elements is hydrogenation, which also is used to upgrade the fuel. However, hydrogenation is expensive, because of the large amounts of hydrogen consumed, and will likely be limited to only the degree that is necessary to market the fuel.[14] If the fuel is upgraded to gasoline or high quality No. 2 fuel oil, most of the sulfur and nitrogen will be removed and there should not be any significant problems. However, that portion of the synthetic crude which may be burned with little or no refinement could contain relatively high levels of these elements (up to 0.5 percent sulfur and 0.8 percent nitrogen) and represents more of an environmental hazard than gasification products.

In addition to lead and arsenic, mentioned above, other trace elements found in coal include antimony, boron, bromine, cadmium, fluorine, mercury, nickel, uranium and thorium. These substances could accumulate in sediments and prove to be toxic to aquatic life. Most trace metals, however, will be removed with the coal ash. Under the zero aqueous discharge approach, dissolved metals would be concentrated in brines for ultimate disposal.

Several potential problem areas concerning airborne pollutants from coal conversion facilities have been identified.[70] Among these problems is the potential loss of volatile photochemically reactive organic vapors which could serve as precursors for such pollutants as ozone, peroxyacyl nitrates, aldehydes, sulfate and nitrate aerosols and cresols. Such hydrocarbon emissions may also be toxic or produce toxic substances when photo-oxidized. Emission of these materials could come from unincinerated vent gases from acid gas removal, leaks in valves, flanges and other fittings, or equipment failures. Atmospheric emissions of volatile, potentially toxic chemicals can also occur from the aqueous condensates in cooling towers. These cooling tower emissions could give rise to both health and environmental problems.

In addition to the pollutants just described, direct stack emissions from steam boilers of sulfur dioxide, oxides of nitrogen and particulate will also occur. Their control, however, should be rather straightforward due to the similarity between these steam boilers and existing industrial and power plant boilers.

As alluded to above, coal conversion facilities will generate large quantities of solid wastes. Since pollutants such as heavy metals are more easily removed by processes using gasification than direct liquefaction, one might project that direct liquefaction products would contain greater amounts of these heavy metals than indirect liquefaction products. However, it is likely that the heaviest fraction of the direct liquefaction product, that containing most of the heavy metals, will be gasified to produce hydrogen. If this is the case, there will be little inherent difference in the solid wastes of direct and indirect liquefaction processes.

This discussion brings up the issue of catalyst disposal. Both indirect and direct liquefaction processes utilize catalysts. Although most catalysts are reprocessed when spent, some cannot be reprocessed economically and therefore require disposal. Methanol and the F-T process utilize one type of catalyst and the Mobil MTG process utilizes two types of catalyst in their liquefaction steps. While, in the case of methanol, the catalyst is currently being disposed of in the U.S. with no known problems, the use of coal as a feedstock could potentially increase the impurities reaching the catalyst and therefore residing on the disposed catalyst. The H-Coal process also utilizes a catalyst in its liquefaction step while the SRC-II and EDS processes utilize catalysts at other steps. Thus, there apprears to be no distinct advantage for either direct or indirect processes in this area.

The remaining distinct difference between the environmental effects of coal gasification and coal liquefaction processes (prior to end-use) is in exposure to the fuel itself, after production and in distribution. While coal liquids are for the most part hydrocarbons and, as such, are similar to petroleum, they have a higher aromatic content and some may contain significant quantities of polycyclic and heterocyclic organic compounds. Some of these compounds are definitely mutagenic in bioassays and many have produced tumors in animals. Thus, while the noncarcinogenic health effects of these materials would be more similar to those of crude petroleum, they would definitely have the potential to be more carcinogenic. There is also some evidence that much of this bioactivity can be removed by moderate to severe levels of hydrogenation which would occur if high grade products were produced. Thus, again the potental hazard is dependent upon the degree of hydrogenation given the products.

Indirect liquefaction products, on the other hand, do not appear to exhibit mutagenicity or carcinogenicity. Methanol is neither mutagenic nor carcinogenic and early tests run on M-gasoline have shown it to be nonmutagenic, similar to petroleum-derived gasoline. Thus, either of these two products offers some degree of benefit over direct liquefaction products. It is possible that methanol produced from coal may contain impurities and that such impurities may affect exhaust products when used. However, little research exists on this issue and such impurities, if any do indeed exist, may be removed during processing.

Methanol, of course, is highly toxic in heavy exposures, leading to blindness or death. Much of its notoriety in this area is due to people confusing it with ethanol and drinking it in large quantities. Hydrocarbon fuels, while also being toxic, do not suffer from this confusion and are not often taken internally. With proper education of the public, methanol's confusion with ethanol should be curtailed. However, more work is still needed in this area.

The absorption of methanol through the skin is also hazardous, more so than gasoline (though the presence of benzene, a carcinogen, in gasoline complicates this issue). Given the public's rather careless use of gasoline, widespread use of methanol would have to be accompanied by an intense campaign to inform the public of the dangers involved. However, given proper warning and identification, and the public's ability to handle other harmful but widely available products, such as pesticides and herbicides, it would appear that a satisfactory level of safety should be attainable.

The final point which deserves mention here is the difference between the effect of an oil spill and a methanol spill. The effects of oil spills are well known; oil films stretching for miles, ruined beaches, surface fires, etc. The effects of a methanol spill are expected to be quite different, primarily because methanol is soluble in water. While high levels of methanol are toxic to fish and fauna, a methanol spill would quickly disperse to nontoxic concentrations and, particularly in water, leave little trace of its presence afterward.[71] Sea life should be able to migrate back quickly and plant life should begin to grow back quickly, though complete renewal would take the time necessary for new plants to grow back. Also, if a methanol fire would start, it could be effectively dispersed with water, which is not possible with an oil fire. However, methanol flames can be invisible, which would be a disadvantage relative to gasoline. This disadvantage could potentially be reduced or eliminated through the use of additives which would provide flame luminosity.

The various relative environmental aspects of synthetic fuels mentioned above are those which appear to stand out at this time. More work, however, is still needed in most areas. Although natural gas to methanol plants exist and have led to much experience in handling methanol, questions related to methanol production from coal have not been answered with absolute certainty since such large scale facilities do not currently exist in the U.S. (Methanol is commercially produced from coal in South Africa, but without acceptable pollution controls by U.S. standards.) Similarly, no real life experience of the effects of the production of synthetic crudes exists, nor of their use. Given these caveats and the need for further research, however, the indirect liquefaction route to yield methanol or gasoline (from methanol) appears to have some potential environmental advantages over direct liquefaction processes.

III. Practicalities of Distributing Another New Fuel

As was just shown, the production of methanol appears to have a fair number of technological and environmental advantages over the production of syncrudes. After production, however, the methanol must be distributed to retail fuel outlets for final purchase. This would mean adding a new fuel to the distribution system. This problem has often been cited as a major one for methanol, both because of the initial cost of conversion and because roughly twice the volume of methanol must be distributed as that of gasoline due to methanol's low energy density. In this section, the difficulties of adding another fuel to the distribution system will be presented. The economics of distribution will be discussed later in conjunction with the economics of producing and using methanol (Section V).

While some have emphasized that introducing methanol would be a tremendous task, and this may be true, it is important to note that the nation has already successfully encountered the problems associated with the somewhat analogous introduction of a new fuel in the very recent past. This occurred when unleaded gasoline was required for use in all post-1974 cars that were equipped with catalytic converters. The required addition of this new fuel to the marketplace went through a remarkably smooth transition. This was in spite of the fact that in the period of only one year, use of unleaded gasoline went from near zero to roughly 10 percent of the gasoline market. The government requirement that gas stations over a certain size carry unleaded gasoline helped significantly, particularly in the early days of the 1975 model year.

Since it is not expected that use of methanol would be required for all or most of the new vehicles in a certain model year, the introduction of neat methanol could follow a slower pace. Of course, a slower introduction would mean that methanol would initially be supported in the market place by a smaller sales volume and that per gallon mark-ups may need to be greater than they were for unleaded gasoline. However, before methanol becomes available on a commercial scale at retail outlets, it is expected that fleets will be the first significant users of methanol. This is due primarily to the fact that fleets tend to operate from fixed central locations. Thus, with little total investment, fleets can have their own facilities to store and distribute methanol fuel and not have to be concerned that methanol is not yet available everywhere.

This is already actually occurring on an experimental basis. The Bank of America is experimenting with the use of neat methanol in its corporate fleet. It's current fleet test of methanol has accumulated more than 500,000 miles so far. By 1985, it is expected that 500-600 Bank of America vehicles will be converted to methanol. Eventually, the Bank of America intends to convert its entire fleet of 1,800 vehicles to methanol or methanol-blend fuel.

Another segment of the transportation spectrum that could utilize methanol fuel before it was widely available would be intracity transit bus fleets. These vehicles also tend to originate and return to fixed central locations that could also easily convert to methanol distribution. Given that methanol engines are expected to be able to at least approach and possibly attain the fuel efficiency of the diesel (see next section) without the presence of diesel smoke or odor, which are easily noticed by the public, transit authorities may have some incentives to consider methanol as an alternative to diesel fuel.

Eventually, however, methanol will need to be available at commercial outlets. Two factors will help make the transition easier than would otherwise have been the case. One, use of leaded gasoline will be decreasing steadily between now and the early 1990's. This will provide storage tanks and pumps for a new fuel, since the same equipment can to a large extent be used to store and pump methanol with only minor changes to rubber components. (It should be noted that some storage tanks, particularly newer ones, are made of fiberglass, which is not compatible with methanol. These will need to be either replaced with carbon steel tanks or with new fiberglass tanks lined to prevent contact with the fiberglass.) Two, as evidenced by the existing diesel passenger car market, not every gas station has to market a given fuel to support a small fleet of vehicles. Certainly, very few urban gas stations currently market diesel fuel. Yet the diesel car market is flourishing. The same could be true for methanol-fueled cars. Indeed, the diesel truck fleet has survived for a long time on a small number of stations carrying diesel fuel. The stations are simply along the routes most frequently traveled by line-haul trucks.

The largest problem facing the introduction of methanol fuel will likely be coordinating methanol production/distribution with the production of methanol-fueled vehicles. Each industry usually points to the other and says that we will produce the cars when the fuel is available or we will produce the fuel when the cars are available. Of course, neither can afford to invest in producing the fuel or the vehicles without some guarantee that the other will occur simultaneously.

Consumption of neat methanol would likely begin with corporate and transit fleets with captive fuel supply systems. The next step would be the biggest one, to a distribution system which would support the public sale of methanol-fueled vehicles. This could require government incentives or requirements to carry neat methanol fuel or it could occur through the government purchasing such vehicles and a small fuel supply market growing to supply this fleet. After this the market would decide the rest and determine if methanol was an economical fuel vehicle choice or not.

Overall, there are a number of distribution-oriented problems to be solved before methanol could be widely available as an automotive fuel. Indeed, overcoming the inertia of the presence of the existing distribution network for gasoline and diesel fuel is probably the greatest obstacle facing the introduction of methanol as an automotive fuel. Surely there would be conversion costs involved and possibly some expansion because of methanol's lower energy density. However, the great majority of the capital represented by the existing distribution network is compatible with methanol and would not require total replacement. Conversion costs need to be fully considered when determining whether or not methanol is an economic alternative. However, the greater problem appears to be simply organizing the various parties involved so that each can be confident of the other's actions in moving ahead with a new fuel.

IV. Use of Methanol in Vehicles

As suggested in the introduction, there are many potential uses for methanol fuel. In the electric power generation industry, methanol may be an attractive fuel for peaking turbines and may also be suitable for base-load plants (with no need for costly scrubbers).[15,72,73,74] Methanol can also be used as a chemical feedstock.[15,75] However, the emphasis here will be placed on the use of methanol in motor vehicles. It is in the motor vehicle area that methanol has the greatest potential for displacing foreign crude, since transportation uses account for more than half of all petroleum currently consumed by the nation.

The following represents a review of existing research and literature produced by other government agencies, industry, and other private institutions. EPA, itself, has begun an evaluation effort of its own on pure methanol use in motor vehicles, although the results of this early work was not available to be included in this report. However, it is expected to closely follow the results of the promising data produced here by other institutions, although considerable work remains to be done.

The emission characteristics of methanol engines will be discussed first, followed by the fuel consumption characteristics of such engines. The data presented were obtained from tests of actual methanol engines. However, two things should be said about these data. One, the data were taken using engines which were only roughly converted to use of methanol and optimized engines would be expected to show further improvements in fuel efficiency and emissions. Two, these data should not be taken as a literal demonstration that methanol engines could be mass produced immediately for use in all regions of the U.S. There are some technical difficulties associated with the use of methanol which have yet to be solved to full satisfaction, though serious attempts to solve these problems have only begun very recently. It is safe to say that these problems are relatively minor and that if the fuel were available there would be engines available to use it. This has been stated clearly by the domestic auto industry.

The worst problem centers around methanol's low vapor pressure and high heat of vaporization. These properties make it difficult to start a neat methanol engine in cold weather.[76] Also, methanol has a very low cetane number of 3, which means that it is very difficult to ignite in a compression-ignition engine (e.g., a diesel). Problems associated with materials compatibility and lubrication also exist, but these problems already appear to be solvable with existing technology, requiring only that the auto designer know that methanol is going to be the engine fuel.

Various techniques are already being tested which will improve the cold-starting capability of gasoline engines operating on methanol, such as better mechanical fuel atomization, electrical fuel preheating, and the blending of volatile, low boiling point components into the methanol. Methanol's ignition problems are more serious in diesel engines, but several possible solutions are being investigated, such as intake air preheating, turbocharging, glow plugs and spark ignition. Brazil already has an experimental methanol-fueled diesel running on the road which uses relatively inexpensive glow plugs as ignition aids and M.A.N. in Germany has designed a diesel bus engine with spark ignition which runs on methanol.[77,78]

As will be evidenced by the section on fuel consumption, the fuel properties of methanol which lead to these difficulties also lead to many advantages, such as increased thermal efficiency. As has been the case with both gasoline and diesel engines in the past, the disadvantages of a fuel can usually be overcome to allow exploitation of the advantages.

A. Emissions

Methanol engines promise improved emission characteristics over gasoline and diesel engines in a number of areas. Especially important are low emissions of nitrogen oxides (NOx) and an absence of emissions of particulate matter, heavy organics and sulfur-bearing compounds. One possible side benefit of methanol use could be that precious metal catalysts might not be needed. Because methanol fuel will contain no sulfur, phosphorus, lead, or other heavy metals, base metal catalysts (e.g., nickel, copper, etc.) may suffice. One likely negative impact of methanol engines would be an increase in engine-out aldehyde emissions, particularly formaldehyde. Catalytic converters, however, would be expected to reduce aldehyde emissions by at least 90 percent. The available data supporting these effects are discussed below.

A search of the literature shows a general consensus that methanol engines produce approximately one-half of the NOx emissions of gasoline engines at similar operating conditions, with individual studies showing reductions between 30 percent and 65 percent.[78,79,80,81,82] One of the major engine design changes expected with methanol engines is the use of higher compression ratios to increase engine efficiency. Experiments have confirmed the theoretical expectation that these higher compression ratios, with no other design changes, will increase NOx emissions considerably due to the higher combustion temperatures.[83,84] However, with high compression ratios, less spark timing advance is needed. Retarding spark timing is known to reduce both NOx emissions and engine efficiency. Fortunately, it has been shown that the combination of a much larger compression ratio with a few degrees of spark timing retard can both increase thermal efficiency and decrease NOx emissions.[84] This raises the possibility of methanol light-duty vehicles being able to meet the current 1.0 gram per mile NOx emission standard without the need for a NOx reduction catalyst.

Use of methanol in a diesel engine should also reduce NOx emissions by the same degree as that described above. Diesel engines have higher peak combustion temperatures and the effect of a cooler-burning fuel should actually be even more apparent in a diesel than in a gasoline engine. Unfortunately, no data to confirm this is yet available from a diesel engine running on pure methanol. However, emission tests have been performed on a dual-fuel diesel, where a small amount of diesel fuel is injected to initiate combustion of the methanol. These tests have shown NOx emission reductions as high as 50 percent.[85,86]

Finally, the use of methanol should also provide a method for heavy-duty engines to reduce NOx emissions closer to the congressionally-mandated level without giving up any of the fuel economy advantage of the diesel, as will be seen later.

The lack of hard data on diesels operating on pure methanol indicated above will also be evident below as other aspects of methanol-fueled diesel engines are discussed. The basic reason for this lack of data is that until recently methanol has not been seriously considered to be an acceptable fuel for a diesel engine because of its very low cetane number of about 3. For many years, studies examining methanol as an engine fuel concentrated on gasoline-type (fuel inducted with combustion air) engines. However, as the more recent studies are indicating, it appears possible to burn methanol in a diesel accompanied with some kind of ignition assist and, therefore, utilize the efficiency of the diesel concept.

In addition to the positive effect on NOx emissions, use of methanol engines should provide even greater benefits with respect to emissions of particulate matter and heavy organics from diesels. Gasoline engines operated on unleaded fuel emit only small quantities of particulate matter, which is primarily sulfate emissions. Thus, any improvement in particulate emissions from switching to methanol from gasoline would be small.

However, diesel engines emit significant quantities of particulate matter. This type of particulate emission is of particular concern due to its small size, its impact on air quality where people live and work relative to other large sources of particulate emission, and the finding that its extractable organic fraction is mutagenic in short-term bioassays. Recent, more detailed biological studies appear to be predicting a lower level of carcinogenicity than originally thought might be present. Still, even absent an absolute finding on the cancer issue, particulate emission standards have been promulgated for diesel passenger cars and light trucks by EPA and recently standards have been proposed for heavy-duty diesel trucks. Diesel particulate matter consists of solid carbonaceous particles (soot) and liquid aerosols. The former are generally formed when fuel-rich mixture pockets burn and form carbon particles. These solid particles can then serve as nuclei for organic species to adsorb onto and as "vehicles" for such compounds to reach (and possibly lodge in) the deep regions of the lung. Although large reductions in diesel engine particulate have been reported, particulate matter seems to be an inherent pollutant in diesel-fueled compression ignition engines.

Methanol, on the other hand, has no carbon-carbon bonds and is a "light" fuel relative to diesel fuel and should produce far less carbonaceous particles. In addition, since methanol does not contain inorganic materials like sulfur or lead, there should not be any other types of solid particulate formed. Accordingly, with pure methanol there would be no nuclei for liquid aerosols to adsorb onto and total particulate emissions would be expected to be near zero.[87] This is certain to be the case with a well designed methanol-fueled spark-ignition engine, which itself may attain the fuel economy of a diesel.[88] Unfortunately, however, we know of no studies which have measured particulate from compression ignition engines burning neat methanol. Several studies (all of which used a small amount of diesel pilot fuel) have reported much lower smoke levels, both in single-cylinder tests and in a 6-cylinder, turbocharged, direct-injected engine.[77,85,89] There seems to be very little question, however, that neat methanol combustion in compression ignition engines would result in very low (and possibly zero) particulate emissions. This would result in a very important environmental advantage compared to diesel fuel combustion and would appear to remove the primary concern associated with large-scale dieselization, that being the diesel particulate/cancer issue.

This discussion of the diesel particulate/cancer issue raises the question of formaldehyde emissions from methanol engines. There is some concern that formaldehyde is carcinogenic. Formaldehyde is an intermediate product in methanol oxidation and would be expected to be emitted from methanol engines in greater quantities than either diesel or gasoline engines. Many studies have shown total aldehyde emissions (mostly formaldehyde) from methanol engines to be two to ten times greater than aldehyde emissions from gasoline engines.[90,91,92,93]

Catalytic converters have been shown to be effective in removing approximately 90 percent of exhaust aldehydes.[79,80, 93,94] Much research has been performed regarding the parameters which influence aldehyde formation in gasoline engines, with low exhaust temperatures and high oxygen concentrations identified as leading to higher formaldehyde formation rates, and this knowledge should facilitate aldehyde control in future engine designs.[92,95] Aldehyde emissions from methanol combustion in diesel engines are also expected to be greater than from diesel fuel combustion. Additional work on the control of aldehyde emissions from methanol engines would be beneficial.

The last benefit of methanol engines to be discussed concerns sulfur emissions. Because of the way methanol is produced it contains essentially no sulfur. And, if there is no sulfur in the fuel, no emissions of sulfur-bearing compounds, such as sulfur dioxide, sulfuric acid, or hydrogen sulfide, can occur. This is a slight improvement over gasoline emissions, since gasoline does have a small amount of sulfur in it. Catalyst-equipped gasoline engines currently emit between 0.005 and 0.03 grams per mile of sulfate and this would disappear with the use of methanol, even if catalysts were still used.

The improvement over the diesel, however, would be more pronounced. Diesel fuel currently contains 0.2-0.5 percent sulfur by weight. This translates into about 0.25 grams per mile of pure sulfur from diesel trucks (0.5 grams per mile of sulfur dioxide, or 0.75 grams per mile of sulfate, equivalent). Diesel cars emit about one-fifth this amount. Since the sulfur level in diesel fuel is expected to rise in the future, these emission levels would also rise in the future. With the use of methanol these emissions would disappear altogether.

A very important secondary effect of removing sulfur from automotive fuel should be mentioned. Along with lead, phosphorus and trace heavy metals, sulfur is one of the more significant deactivators of automotive catalysts (as was mentioned earlier). The presence of these elements is the main reason why precious metal catalysts, such as platinum and paladium, have been necessary. Base metal catalysts, such as iron, copper, nickel, etc., have been shown to be effective but are deactivated too quickly. With methanol, however, not only sulfur, but all of these elements, are removed in production. Thus, catalysts on methanol engines may be able to be of the base metal variety and not include precious metals. This would be a significant economic benefit, since all of our precious metals are currently imported.

B. Fuel Efficiency

The fuel efficiency aspects of using methanol as a fuel will be discussed next. Methanol's effect on the thermal efficiency of an engine will be the focus of discussion, as opposed to its effect on fuel economy (i.e., miles per gallon), since methanol's energy density (Btu's per gallon) differs drastically from petroleum-type fuels. This will be consistent with the next section of the presentation concerning economics, which will focus on the cost per Btu of producing and distributing fuels.

For simplicity of presentation, the discussion will be split into two parts. The first will discuss the effects of using methanol on the thermal efficiency of spark-ignition engines (e.g., the gasoline engine). The second will present the same for compression-ignition engines (e.g., the diesel engine).

There is general agreement among researchers that methanol is a more energy efficient vehicle fuel than gasoline. There are several theoretical reasons why this is so. Methanol's lower flame temperature reduces the amount of heat transfer from the combustion chamber to the vehicle coolant system. Its high heat of vaporization acts as an internal coolant and reduces the mixture temperature during the compression stroke. These characteristics increase a methanol engine's thermodynamic efficiency, and are realized in experiments without having to make any major design changes in current gasoline engines. Studies have shown these inherent properties of methanol to increase the energy efficiency of a passenger vehicle by 3 to 10 percent with a middle range of about 5 percent.[79,82,83]

Other properties of neat methanol combustion allow even greater efficiency improvements. Its wider flammability limits and higher flame speeds relative to gasoline allow methanol to be combusted at leaner conditions while still providing good engine performance. This lean burning capability decreases the peak flame temperature even further and allows more complete combustion, improving energy efficiency. Early testing on a single-cylinder engine yielded estimated energy efficiency improvements of 10 percent due to leaning of the methanol mixture as compared to gasoline tests.[96] Subsequent vehicle testing has shown relative efficiency improvements of lean methanol combustion of 6 to 14 percent.[78,79] Given these results, it would appear that methanol's lean burning capability yields approximately a 10 percent efficiency improvement over and above the 3-10 percent improvement mentioned above. Of course, stratified charge engines have been developed to allow leaner combustion of gasoline as well, and this efficiency advantage of methanol would be minimized with respect to a stratified charge engine.

Methanol's higher octane number allows the usage of higher compression ratios with correspondingly higher thermal efficiencies. Early single-cylinder testing has estimated the thermal energy efficiency improvements of the higher compression ratios to be in the range of 16 to 20 percent.[84,96] Unfortunately, little vehicle data exist to confirm these figures, but it must be expected that improvements of at least 10 to 15 percent are likely.

Adding up the possible improvements indicates that methanol engines may well be 25 to 30 percent more energy efficient than their gasoline counterparts when the methanol engine is designed specifically for methanol. Volkswagen has reported energy efficiency improvements of approximately 15 percent for its mid-1970's vehicles modified to run on methanol, with a corresponding power output increase of about 20 percent.[97] While it is true that emission concerns may force some tradeoffs in terms of efficiency, it is also true that, so far, methanol vehicle data have been taken with modified gasoline-fueled vehicles. As with emissions, time and resources will allow much methanol-specific optimization which should improve the energy efficiency of methanol-fueled spark ignition engines even further.

Before moving on to discuss the effect of methanol on the efficiency of compression-ignition engines, it should be noted that the above-stated 25 to 30 percent improvement in the efficiency of gasoline engines is about the same efficiency advantage that is usually quoted for the diesel engine over the gasoline engine. While the relative fuel economies of diesel and gasoline-fueled vehicles may often show a larger advantage for the diesel, it must be remembered that diesel fuel contains 10 percent more energy per gallon than gasoline and that the performance of the diesel is not always the same as the gasoline engine being compared. Thus, with methanol, it may indeed be possible to attain the fuel efficiency of the diesel without its physical size and weight and without its noticeable smoke, odor, noise, and particulate emissions.

As was true with the amount of information available on the emissions of methanol-fueled compression-ignition engines, there is limited data on the fuel efficiencies of such engines. The most comprehensive data involving neat methanol in a diesel engine is from the MAN-FM direct injection diesel engine which utilizes spark ignition and a unique type of mixture formation. The majority of the methanol is deposited on the wall of the spherical combustion chamber in the piston. The methanol evaporating from the film forming on the wall is successively fed into the flames by the air rotating in the combustion chamber, with most of the heat necessary for evaporation supplied by flame radiation. Initial tests of this design were conducted in a non-commercial air-cooled 4-cylinder engine in a small cross-country military vehicle. Results over an unspecified test cycle showed an energy efficiency improvement of 12 percent with methanol as compared to operation on diesel fuel. The same design was then utilized in a 6-cylinder engine installed in a commercial city bus. With a low-speed stop-and-go test cycle to simulate urban traffic conditions, the bus yielded 5 percent better energy economy with methanol than with diesel fuel. Previous testing had indicated that methanol's efficiency advantage over diesel fuel would likely be greater at heavier loads.[98]

A second set of data involving neat methanol (with 1 to 2 percent castor oil for lubricity) utilized a 3.9-liter, four-cylinder engine with glow plugs to initiate ignition, a design concept which takes advantage of the high detonation ("knocking") resistance and low surface (or "hot spot") pre-ignition resistance of methanol.[77] (While methanol requires higher air-fuel mixture temperatures to self-ignite, the presence of a hot surface has been shown to trigger pre-ignition of methanol to a greater extent than for other fuels. This is likely due in part to the dissociation of methanol at high temperatures to carbon monoxide and hydrogen, with the latter breaking down into various radicals triggering pre-ignition.[99] While this surface ignition phenomenon would be of some concern in a spark-ignited engine because of the possibility of the center electrode of the spark plug promoting pre-ignition in advance of the spark, it might be advantageously utilized in a compression ignited engine to initiate combustion.) Steady-state tests with this engine have shown significantly higher brake thermal efficiencies for methanol compared to diesel fuel above 30 percent load, ranging as high as 22 percent greater, while diesel fuel was more efficient at lower loads.[77] One other study, utilizing a single-cylinder, dualfuel engine (methanol and diesel fuel) reported slightly higher efficiency for methanol, while two other dual fuel studies, one with a single-cylinder engine and the other with a 6-cylinder turbocharged engine, also showed methanol to be somewhat more efficient at higher loads but similar to diesel fuel at lower loads.[85,86,89]

It cannot be overstated that much work needs to be done in the area of methanol use in diesel engines. The primary problem has been the initiation of combustion, and researchers continue to examine several solutions including pilot fuels (usually diesel fuel), glow plugs, spark ignition, cetane-improving additives, etc. Based on the early engine results reported above and the huge opportunity for basic improvements in this area, it seems likely that, should methanol prove feasible in diesel engines, it will actually be a slightly more energy efficient fuel. Even if it should only match diesel fuel in cycle efficiency, it would still provide many environmental benefits (primarily particulate and NOx emissions reductions) compared to diesel fuel.

V. Economics of Production and Use

There have been many studies undertaken in the last five to ten years to determine and compare the costs of producing and/or using synthetic fuels (including methanol). However, a superficial review of the conclusions of these studies would quickly reveal that there is a wide variety of conclusions and recommendations being put forth.

We have analyzed a large number of these studies to date and have found a number of reasons why this is so. One, the economic bases used by the various studies often differ, affecting costs by as much as 100 percent. Two, each study uses the best information available at the time of the study. Since the product mixes, efficiencies and costs of many of these processes, especially the direct liquefaction processes, change frequently as more is understood about the process, studies performed even 2 or 3 years ago cannot be compared to the latest studies. This is especially true in cases where information was at first totally lacking and assumptions had to be made.

We have attempted to go back in each instance to the original engineering studies to assess the reasonableness of the cost estimates. We also have compared the available designs of each process to ascertain which are out-dated or based on now inaccurate assumptions. After doing this, placing everything on the same economic basis, and adjusting for plant size, we have found surprisingly good agreement within each process. For some processes, for example, EDS, this is not surprising since there is really only one spokesman for the process details, Exxon. For others, though, such as methanol production where there are many cost estimates, most of the differences can be attributable to differences in gasifier/synthesis technology. In those cases where there is only one spokesman, we have attempted to compare the results to other similar processes to insure that the assumptions and estimates were reasonable. This last step has not yet been completed as there are some significant economic differences between the processes which are not totally explainable as of yet. These will be highlighted below as the pertinent costs are described.

The results of this analysis indicate that methanol from coal will be less expensive than transportation fuels from direct coal liquefaction. However, several caveats could affect this conclusion. This analysis did not attempt to standardize the engineering techniques used by the outside references in deriving costs. These may differ and assumptions about such factors as reliability, redundancy and process designs, have not been examined. The analysis only standardized economic assumptions. However, the level of engineering design applied in each study was a factor considered in arriving at the best cost estimates for each technology. Thus, the cost estimate for each technology represents the greatest degree of engineering detail available at this time. The final answer will, of course, remain unclear until commercialization and the conclusions of this economic analysis must be considered preliminary.

While the difficulties and apparent discrepancies described above primarily involve the costs of producing synthetic fuels, the overall economic picture involves more. The entire process of producing synthetic fuels and using them in motor vehicles will be broken down into three areas. The first area consists of the production of a usable liquid fuel from raw materials. The second area consists of distribution of this fuel. Finally, the third area includes the use of these fuels in motor vehicles. All costs will be presented in 1981 dollars.

In the first two sections, the costs of producing and distributing all synfuels will be determined on a per energy basis ($ per million Btu (mBtu)). However, it must be remembered that the total amount of energy being produced and delivered will be different for the various fuels being examined. Specifically, engines running on methanol are expected to attain fuel efficiencies 25-30 percent higher than that of a gasoline engine and equal that of a diesel engine. To be conservative here, since there are no production methanol engines yet to confirm this improvement, only a 20 percent increase in efficiency will be used. Assuming that the amount of vehicle miles travelled remains constant, the total amount of energy consumed in the form of methanol would be 16.7 percent less than would have occurred if gasoline were the fuel. This energy (and cost) savings will be considered in the third section and will be presented in the form of an annual fuel savings.

A. Production

Determining the economics of the production of usable synthetic liquid fuels is probably the most difficult of the three areas to be examined here. As mentioned above, we have attempted to go back to the original engineering studies and place all of the costs on the same engineering and economic bases. The engineering and financial bases that have been chosen are shown in Tables 8 and 9.

As shown in Table 8, two different sets of financial parameters were chosen. These were selected from a survey of recent studies[9,58,75,100,101,102] done on coal liquefaction processes and represent two extreme cases for capital charge. The low capital charge rate and accompaning parameters were chosen from the ESCOE[9] report while the high capital charge data were taken from the Chevron Study.[100] The important factors yielding these two CCRs are also shown in Table 8.

Table 8

Common Financial Parameters

Financial Parameters	Low Cost Case[9]	High Cost Case[100]
Capital Charge Rate, Percent	11.5	30
Debt/Equity Ratio	40/60	0/100
Discounted Cash Flow Rate of Return on Investment, Percent	Not Available	15
Project Life, Yrs.	20	20
Construction Period, Yrs.	4	4
Investment Schedule, %/Yr.	9/25/36/30	10/15/25/50
Plant Start Up Ratios	50, 90, 100...	50/100
Debt Interest, Real Rate, Percent *	10	-
Investment Tax Credit, %	9	10
Depreciation Method	Sum of Year's Digits	Sum of Year's Digits
Tax Life, Yrs.	15	13
Interest Rate During Construction, Percent *	6	6

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* Excludes the effect of inflation. All calculations performed in constant 1981 dollars.

Table 9

Process Cost Inputs and Other Factors Common to All Studies

Cost Inputs and Other Factors	Value
Product Yield	50,000 FOEB/CD
Coal	
a) Bituminous	$27.50/ton
b) Subbituminous	$17.00/ton
c) Lignite	$10.00/ton
Operating Costs	
a) Utilities	$0.035/kw-HR
b) Working Capital Interest	6% of working capital per year.
c) Fuel Cost	$35/bbl
Scaling Factors	
a) Capital Costs	0.75
b) Labor Costs	0.20
c) Maintenance, Taxes, Insurance, General	Same percentage of plant investment as specified by each individual study.
d) Coal, Catalysts and Chemicals, Utilities, Fuel, Natural Gas	Amount varies directly proportional to plant size.
By-Product Credit	
a) Sulfur	$50/ton
b) Ammonia	$180/ton
c) Phenol	$112.6/bbl
Contingency factor	15%
Inflation Rate	
a) 1976	5%
b) 1977	6%
c) 1978	7%
d) 1979	9%
e) 1980	9%
Real Cost Increases (%/year)	
a) Fuel Oil	2%
b) Natural Gas	2%
c) Coal	0%

The investment schedules which were published for each of these two sets of parameters were also chosen for this report. These are also shown in Table 9. The investment adjustment factor is multiplied by the instantaneous capital to get the full-life capital cost investment for a plant scheduled to begin production in 1990. The real opportunity cost of the investment used was 6 percent per year.[75]

Table 9 shows the remaining input factors. All plants were normalized to 50,000 fuel oil equivalent barrels per calendar day (FOEB/CD)(one FOB equals 5.9 mBtu, higher heating value). The costs selected for bituminous, subbituminous and lignite coals are respectively $27.50, $17.00, and $10.00 per ton. Because capital costs do not usually vary in direct proportion to plant size, a scaling factor is normally used (an exponent) to modify the ratio of plant sizes (by yield). The scaling factor used here was 0.75, which is an average of factors found from various studies.[75,102,103,104] To adjust labor and supervision costs a scaling factor of 0.2 was used. [9,103] The rest of the operating costs were assumed to vary directly with plant size. The inflation rate for adjusting the costs of studies to $1981 was based on the Chemical Engineering plant cost index.

The costs of producing finished products from five synthetic fuel processes (from coal) will be presented below: EDS, H-COAL, SRC-II, methanol, and MTG. The costs and their sources of each will be presented in the order shown above and then compared as much as possible. Following this, the cost of producing methanol from wood will be discussed briefly.

EDS: There have been a number of reports and papers presented in the literature which discuss the economics of the EDS direct liquefaction process or simply present the cost of the EDS products.[9,45,75,105] These reports include the ICF and ESCOE studies mentioned earlier. All of these reports were based on the 1975/1976 study design prepared by Exxon Research and Engineering (ER&E).[106] All of the economic figures presented here are based on the most recent study design published by ER&E in March, 1981.[48] This recent study design covered the conceptual design of an EDS coal liquefaction commercial plant feeding Illinois No. 6 bituminous coal. This design depicts the state of EDS technology in 1978 as this technology might be applied in a commercial facility.[48] About 20 man-years of effort were required for this work.[48]

Table 10 presents an economic summary of the capital and product costs for the EDS direct liquefaction process. The total instantaneous plant investment as presented in the most recent Exxon study design was used and then placed on a consistent economic basis with the other liquefaction technologies being compared in this study. Product costs based on two different capital charge rates (CCR) (11.5 and 30 percent) are shown. With

Table 10

Direct Liquefaction Product Cost Estimates (Millions of 1 Q 1981 Dollars)

Millions of Dollars	11.5% CCR*			30% CCR*		
	EDS	H-Coal	SRC-II	EDS	H-Coal	SRC-II
Total Instantaneous** Investment	2649	3300	3400	2649	3300	3400
Annual Capital Charge	345	430	440	887	1100	1140
Annual Operating Cost	424	302	346	424	302	346
Total Annual Charge	769	732	786	1311	1402	1486
Liquefaction Product Cost						
$/FOEB of Product	42.16	35.34	41.60	71.83	67.67	80.00
$/mBtu of Prod.	7.15	5.99	7.05	12.18	11.47	13.56

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* CCR = Capital Charge.

** Investment if all capital equipment were purchased and installed in one day, i.e., an instant plant.

a capital charge rate of 11.5 percent the product cost is $42.16/FOEB ($7.15 per mBtu). With a 30 percent capital charge rate the product cost is $71.83/FOEB ($12.18 per mBtu).

Table 11 presents a breakdown of the investment and operating cost for the EDS liquefaction plant. The total instantaneous investment in first quarter (1Q) 1981 dollars is $2.65 billion. The total annual operating cost per year is $452 million before taking a byproduct credit of $28 million. Coal represents about 50 percent of the operating costs while repair materials account for 21 percent and utilities 14 percent.

Table 12 presents a breakdown of the annual capital charge and operating costs as a percentage of product cost. With a CCR of 11.5 percent the annual capital charge accounts for 42 percent of the product cost while coal accounts for 29 percent. With a CCR of 30 percent the annual capital charge accounts for 65 percent of the product cost with coal accounting for 17 percent. It should be noted that none of these costs include the cost of refining. For all three direct liequefaction precesses, the refining costs will be presented later and then included in a summary table.

H-Coal: The cost estimates of the H-Coal product was based on cost estimates of a 50,000 barrels per day commercial plant by Ashland Oil.[44,46] A few other studies have also determined product costs for H-Coal.[9,75,106] However, the Ashland analyses should best represent the product costs of H-Coal liquefaction, primarily because the Ashland studies are very recent (1981) and have a more accurate description of the process costs. Although another study performed by EPRI is also recent (1979), the projected technology and costs have changed dramatically even within those two years (i.e., from 1979 to 1981). Costs associated with the updated technological and process developments have escalated much more rapidly than inflation. Thus, the Ashland product costs should be the most accurate available to date. These costs were then adjusted using the common financial and engineering parameters shown in Tables 8 and 9.

Table 13 shows the capital and product cost estimates. The instantenous capital investment, which includes a 15 percent contingency and a refinery cost for light naphtha to reformate (does not duplicate later refinery costs) is $3.3 billion. The annual operating costs, as estimated by Ashland, are $134 million which does not include feedstock costs and capital recovery. The annual capital recovery, with the adjustment lifetime investment from instantaneous investment, and with the appropriate capital charge rates, is $0.43 - $1.10 billion (depending on the CCR). The feedstock cost is estimated to be $181 million per year, and by-products credits amount to $13 million per year. The total annual cost is estimated to be $732 million to $1,402 million per year. Total product cost is $35.34-67.67 per FOEB/CD, depending on the CCR ($5.99-11.47 per mBtu)(see Table 10).

Table 11

EDS Investment and Operating Costs (1st Q 1981 Dollars)

50,000 FOEB/CD	
Investment Cost (Millions of Dollars)	
Onplot Investment	1281
Offplot Investment	780
ER&E Charges	60
Subtotal	2121
Contingency	309
Total Instantaneous Plant Investment	2430
Working Capital and Startup Costs	219
Total Instantaneous Capital Investment	2649
Operating Cost (Millions of Dollars Per Year)	
Capital-Related	
Interest on Working Capital	7.1
Repair Materials	114
Salaried and Related Costs	
Wage Earners	34.7
Salaried	9.1
Overhead, Supplies, etc.	8.8
Coal	210
Catalyst & Chemicals	8.6
Utilities, Power	59.7
Subtotal	452
By-product Credits	
Sulfur	12.8
Ammonia	5.4
Phenol	10.0
Annual Operating Cost	424

Table 12

Liquefaction Product Cost Breakdown, % of Cost

	11.5% CCR*			30% CCR*		
	EDS	H-Coal	SCR-II	EDS	H-Coal	SRC-II
Annual Capital Charge	42	58	56	65	78	77
Coal	28.9	24.6	16.4	17.4	12.9	8.6
Repair Materials	6.8	-	-	4.1	-	-
Plant Maintenance	-	6.6	-	-	3.4	-
Utilities, Catalyst and Chemicals	9.4	0.7	-	5.6	0.4	-
Labor & Supervision	5.3	1.6	-	3.2	0.8	-
Local Taxes and Insurance	5.6	7.1	-	3.4	3.7	-
Overhead, Supplies	1.1	1.9	-	0.6	1.0	-
Other	4.8	1.0	39.7**	2.9	0.5	14.5**
Byproduct Credit	(3.9)	(1.8)	(1.7)	(2.3)	(1.0)	(0.9)

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* CCR = Capital Charge Rate.

** These include the annual operating costs other than feedstock costs. For SRC-II, annual operating costs could not be broken down further, based on available data.

Table 13

H-Coal Investment and Operating Costs (1st Q 1981 Dollars)

Ashland Case	50,000 FOEB/CD
Investment Cost	
(Millions of Dollars)	
Direct Costs	
Liquefaction Plant	690
Oxygen and Hydrogen Plants	320
Other Refinery Units	125
Tankage, Interconnecting Piping	120
Coal Handling, Boilers	360
Wastewater/Solids Treating	200
Other Offsites	185
Field Indirect Cost	400
Miscellaneous Field Costs	80
Engineering and Fee	280
Subtotal	2760
Contingency	400
Total Instantaneous Investment	3160
Working Capital	140
Total Instantaneous Capital Investment	3300
Operating Costs	
(Millions of Dollars per Year)	
Coal	181
Plant Maintenance	43.9
Salaried and Related Costs	
Direct Labor and Supervision	10.7
Overhead, Supplies, etc.	12.5
Power, Catalyst, and Chemicals	4.6
Indirects, G & A	7.0
Local Taxes and Insurance	47.5
Interest on Working Capital	7.6
By-Product Credits	
Sulfur	0.1
Ammonia	13.0
Phenol	0.4
Annual Operating Costs	302

SRC-II: The cost estimates of the SRC-II product were based on cost estimates by DOE and Pittsburg and Midway Coal Mining (P&M).[51,63,64] The latest cost estimates from DOE and P&M were based on 1981 cost estimates of the 6000 TPD demonstration plant that was to be constructed in Morgantown, West Virginia. The cost estimates of the demonstration plant were then scaled up to a 50,000 FOEB/CD commercial size plant (see Table 14). Although an EPRI study also performed a detailed cost analysis of the SRC-II process,[107] their cost estimates were mid-1976 estimates and could not simply be inflated to 1981 dollars because of the rapid increase in process costs due to actual design changes and not simply inflation.

The product and capital costs for SRC-II are shown in Table 10. The capital costs amount to $3.4 billion dollars when scaled to a production of 50,000 FOEB/CD, including a 15 percent contingency factor.[51] With the appropriate capital charge rate, the annual capital recovery cost is $440-$1,140 million. The annual operating cost is $346 million, not including a feedstock cost of $168 million per year. By-product credit is about $17 million per year. The total annual cost is $760-$1,460 million. The average product cost is $41.60-80.00 per FOEB ($7.05-13.56 per mBtu)(see Table 10).

Syncrude Refining: Investment and operating costs for coal liquid refineries have been reported in a few different studies. Cost estimates for SRC-II syncrude have been made by Chevron and ICF.[59,75] Cost estimates for H-Coal syncrude have been made by UOP, ICF, and Exxon.[60,75,108] The only estimate available for the EDS syncrude was made by ICF.[75] Also Exxon has prepared a rough study which presents a range of costs for upgrading a coal liquid in general.[109]

The economic basis for the refining costs is identical to the basis discussed previously, except that the plant size for the refineries was adjusted to a feedrate of 54,500 BPCD using a capital scaling factor of 0.75.

An analysis of the Chevron/SRC-II and UOP/H-Coal studies indicated that they were based on a significantly higher level of engineering design than the other studies. Thus, their cost estimates were used to estimate the refining costs for the SRC-II and H-Coal syncrudes. Since no detailed study was available on the refining of the EDS syncrude, this needed to be estimated, similar to the situation earlier with refining efficiency and product slate. The ICF study mentioned earlier did address EDS refining, but in much less detail than Chevron or UOP.[75] ICF's EDS refinery only hydrotreated the various straight-run products and used natural gas to produce the necessary hydrogen.[75] Neither the resultant efficiency nor the product slate was comparable to the Chevron or UOP refineries, so the ICF results were not used. Instead, estimates of the EDS efficiency and

Table 14

Cost Estimates for SCR-II
(Millions of 1st Q 1981 Dollars)

	6000 TPD Demonstration Plant	50,000 FOEB/CD Commercial Plant
Design	292	632
Construction	1415	3058
Start-up	286	619
Contingency (15 percent)	299	647
Total Lifetime Capital Lost*	2292	4956
Average Annual Operating Costs	160	320
Feedstock Costs	59	168
By-product Credit	6	17

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* Not instantaneous capital cost. Uses DOE construction schedule and interest rate.

product mix were based on the Chevron and UOP results. With respect to refining costs the ICF estimates appeared very reasonable compared to the Chevron and UOP results for the 30 percent CCR, but not the 11.5 percent CCR. Thus, an interpolation of the Chevron and UOP costs was used instead of the ICF cost estimates.

Table 15 presents the economic summaries of the investment, operating, and refining costs in first quarter 1981 dollars for the three coal liquid refineries. The operating costs do not include the cost of the syncrudes. The refining cost per mBtu of refined product for the SRC-II, H-Coal, and EDS syncrudes are $1.84, $1.06, and $1.31 for the 11.5 percent CCR; and $3.80, $2.10, and $2.58 for the 30 percent CCR, respectively.

These refining costs can now be added to the liquefaction costs to obtain an overall cost of producing finished products. These overall, or average, costs can then be allocated among the various products in a manner that will simulate their market demand (i.e., more costs per mBtu are allocated to those products which will demand higher market values). However, the first step is not simply a matter of adding the average liquefaction cost ($ per mBtu) to that for the refining. First, not all of the liquefaction products go through the refinery so the refinery cost should not be added to them. Second, some of the liquefaction product is lost in the refinery (it is not 100 percent efficient) and its cost must be included.

While accounting for these two factors is a simple algebraic matter, allocating costs among the various products is more difficult. There is no right answer since no one can exactly predict the future. Fortunately, all the processes being discussed here produce a large amount of gasoline (or methanol) and changes in the relative values of the other products will not have as large an effect as it would if the processes were producing large amounts of medium-Btu gas, residual oil, etc.

It is generally appropriate to attempt to allocate the costs of processing in accordance to the expected market values of the various products. To do otherwise would be to mislead oneself that the premium products of a process were relatively inexpensive (while the low quality products would also be misleadingly expensive). Thus, some relationship between the values of the various fuels was needed in order to determine representative costs for each fuel.

A product value approach was utilized here to estimate costs for individual products. This technique assumes that future energy prices for particular products will maintain a fixed ratio to each other. All prices are normalized relative to a reference product, which here was chosen to be gasoline. In this report, a

Table 15

Refining Cost Estimates (Millions of 1 Q 1981 Dollars)

Millions of Dollars	11.5% CCR*			30% CCR*		
	Chevron/ SRC-II[51]	UOP/ H-Coal[52]	EDS	Chevron/ SRC-II[51]	UOP/ H-Coal[52]	EDS
Total Instantaneous Investment	781	454	-	781	454	-
Total Adjusted Capital Investment	1034	602	-	1022	595	-
Annual Capital Charge	119	69	-	307	178	-
Annual Operating Cost	58	42	-	58	42	-
Total Annual Charge	177	111	-	364	220	-
Refining Cost:						
$/bbl of Product	9.76	5.75	6.90	20.13	11.41	15.22
$/mBtu of Product	1.84	1.06	1.31	3.80	2.10	2.58

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* CCR = Capital Charge Rate.

relationship between various fuels similar to that reported in the ICF report was used and is as follows:

1. If the cost of unleaded regular gasoline is $G/mBtu,
2. The cost of No. 2 fuel oil is (0.82)(G)/mBtu, and
3. The cost of LPG is (0.77)(G)/mBtu.[75]

Since unleaded premium gasoline is produced in some cases (EDS and H-Coal), a relationship between this fuel and regular gasoline is necessary. Since a history of the relationship between these two fuels was not readily available, a history of the cost ratio of leaded premium to leaded regular gasoline was used. This relationship indicated a cost ratio of 1.075.[110] This product cost relationship was then applied to premium and regular unleaded gasoline.

A price relationship between SNG and the reference was also needed. This may be determined by assuming that SNG will have the same relationship to gasoline as natural gas. However, the well-head price of natural gas is just in the process of being deregulated; therefore, it is incorrect to use the current gasoline/ natural gas price relationship. Instead, a method used by Mobil, and a method which relates the natural gas price to that of No. 2 fuel oil were both utilized. These two methods are described below.

As discussed earlier, one of the scenarios examined by Mobil was the co-production of SNG and gasoline.[10] To obtain a realistic value for the SNG produced, Mobil estimated the cost of SNG from a coal-gasification plant producing essentially 100 percent SNG. Using this cost for SNG, they then allocated the remaining cost to the gasoline. The result was that the SNG cost 77 percent as much as the gasoline on an energy basis (i.e., it was cheaper on an energy basis to produce SNG solely than to co-produce SNG and gasoline).

Another technique to obtain a representative SNG/gasoline cost relationship is to assume that SNG has the same value as No. 2 fuel oil. This is reasonable since both have at least one large common market in industrial and domestic heating. Using this method, the cost ratio of SNG to gasoline would be the same as that for No. 2 fuel oil, 0.82.

Since the two techniques yielded very similar results, it was decided to average the two cost ratios. Therefore, the SNG/unleaded gasoline cost ratio used in this report is 0.80.

Table 16 shows the results of combining the costs of liquefaction and refining and of allocating these costs among the various products. (Also shown are the costs for methanol and MTG

Table 16

Product and Capital Costs of Coal Liquefaction Processes(1981 Dollars)

Process	Product Mix	Product Cost ($/mBtu) 11.5% CCR	Product Cost ($/mBtu) 30% CCR	Capital Cost ** (Billions of Dollars)
Direct Liquefaction				
EDS (Bituminous)	32.7% Reg. Gasoline	$10.00	$17.29	$2.65
	14.0% Prem. Gasoline	$10.80	$18.67	
	25.6% No. 2 Fuel Oil	$ 8.20	$14.18	
	9.6% LPG	$ 7.70	$13.31	
	18.1% SNG	$ 8.00	$13.83	
H-Coal (Bituminous)	33.1% Reg. Gasoline	$ 7.79	$14.97	$3.30
	11.2% Prem. Gasoline	$ 8.37	$16.09	
	20.4% No. 2 Fuel Oil	$ 6.38	$12.27	
	22.3% LPG	$ 6.00	$11.52	
	13.0% SNG	$ 6.23	$11.97	
SRC-II (Bituminous)	64.7% Gasoline	$ 9.87	$19.06	$3.40
	12.1% LPG	$ 7.60	$14.68	
	23.2% SNG	$ 7.90	$15.24	
Indirect Liquefaction				
Texaco (Bituminous)	100% MeOH*	5.90-6.46	9.44-10.41	1.99-2.21
Koppers (Bitum.)	100% MeOH*	7.23	12.42	2.92
Lurgi (Subbit.)	47.9% MeOH*	7.04	12.48	2.59
	49.7% SNG	5.63	9.98	
	2.4% Gasoline	7.04	12.48	
Modified Winkler (Lignite)	100% MeOH*	5.70	9.56	2.17
Lurgi Mobil MTG (Subbit.)	41.2% Reg. Gasoline	8.01	14.35	2.95
	53.3% SNG	6.41	11.48	
	5.5% LPG	6.25	11.20	
Mobil MTG Incremental Cost	85-90% Reg. Gasoline	1.45	2.87	0.66
	10-15% LPG			

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* MeOH = 95-98% methanol, 1-3% water, and the remainder higher alcohols.

** Capital costs are instantaneous costs and do not include refinery capital costs.

gasoline, which are discussed below.) Comparison of these direct liquefaction costs will be delayed until the methanol and MTG gasoline costs have been presented.

Methanol: To estimate the cost of producing methanol, thirteen independent studies from nine reports[7,10,16,54,55,56, 57,58,111] were normalized to a production yield of 50,000 FOEB/CD and inflated to $1981 according to the financial assumptions previously mentioned (Tables 8-9). Of these thirteen studies, nine used bituminous coal, two used subbituminous coal and two used lignite to produce the methanol. The studies included eight different coal gasification technologies (Foster Wheeler, BGC/Lurgi, Koppers-Totzek (2), Texaco (4), Lurgi (1), "slag-bath" (1), modified Winkler (2) and Koppers-Shell) and four different types of methanol synthesis units (Lurgi (2), ICI (5), Chem Systems (5), and Wentworth Bros. (1)). As previously mentioned only the Winkler, Lurgi and Koppers-Totzek gasifiers are proven on a commercial scale and the Texaco process is very close to commercialization. Of the synthesis units, ICI and Lurgi are used extensively today. Wentworth Bros. claim that their process is commercial and Chem Systems is a new process which is still being tested.[112] Lurgi and ICI have been competing for the last ten years and both have highly developed processes, good efficiencies and, according to EPRI,[7] room for further improvement is small. In addition, EPRI states that the Chem Systems process only shows a slightly higher thermal efficiency and lower capital cost than the ICI system. Since the costs of the proven ICI and Lurgi synthesis processes are indistinguishable and it appears that the cost for the Chem Systems process is only slightly lower, it has been decided to place most of the emphasis here on the effect of the various gasification technologies which appear to have significant effects on costs.

The original range of product and capital costs reported by the thirteen studies are very large due at least in part to the large range in plant size ($3.74-12.55 per mBtu for product cost and $0.401-$5.05 billion for capital, $1981, for plants ranging from 2,000-58,000 ton per day of methanol). With this type of data it is very difficult to estimate the actual cost of methanol, let alone compare it with any other coal technologies. After normalizing the costs for the thirteen studies the ranges of costs are much smaller. For bituminous coals the product cost ranged from $4.65-9.05 per mBtu for the low CCR and $8.14-12.54 per mBtu for the high CCR. However, since four of these studies had to be scaled up or down significantly (factor of three or more)[55,56,57] it was decided to place the most emphasis on the five remaining studies whose original designs called for methanol plants producing near 50,000 FOEB/CD.

The range of methanol costs from these studies is much smaller, $5.30-$7.23 per mBtu for low CCR and $8.74-$12.42 per mBtu for high CCR. The gasifiers used in these studies are Foster-Wheeler, BGC-Lurgi, Koppers-Totzek, and Texaco(2). Since the Foster-Wheeler and BGC-Lurgi gasifiers are still being developed, it was decided to drop these two studies also. Thus, three studies were left and their product costs are shown in Table 16.

The cost using the Texaco gasifier is $5.90-$6.48 per mBtu for the low CCR and $9.44-$10.41 per mBtu for the high CCR. The cost using the Kopper-Totzek gasifier is $7.23 per mBtu for the low CCR and $12.42 for the high CCR. In retrospect, the resulting price range of $5.90-$7.23 per mBtu for the low CCR and $9.44-$12.42 per mBtu for the higher CCR lies approximately in the middle of the original ranges of $4.65-$9.05 per mBtu and $8.14-$12.54 per mBtu for the original nine studies.

Both of these reactors are entrained bed units which seems to emphasize the statement that entrained bed gasifiers are the only commercially-available reactors today which can economically gasify eastern bituminous coals (seven of the original nine studies used entrained bed gasifiers).

The capital cost range for the original nine studies was $1.93-$2.92 billion (50,000 FOEB/CD plant), which was also the same for the smaller group of five. As shown in Table 16, the instantaneous cost for the methanol plant using bituminous coal was $1.99-2.21 billion when the Texaco gasifier was used and $2.92 when the Koppers-Totzek gasifier was used.

The range of product and capital costs for methanol from subbituminous coals and lignite are smaller than that of bituminous. Of the two studies using subbituminous coals, one uses a proven gasification and synthesis technology, Lurgi/Lurgi,[10] while the other uses a gasification technology which the manufacturer claims is "here and now," and a proven synthesis process, modified Winkler/ICI.[58] The average product cost range is fairly small, $6.16-$6.34 per mBtu for the low CCR and $10.26-$11.24 per mBtu for the high CCR. The instantaneous capital investment range is $2.10-$2.59 billion. Although the costs seem to compare favorably, only the Lurgi/Mobil prices are shown in Table 16. This is because the modified Winkler/ICI plant size had to be scaled up significantly where as the Lurgi/Mobil plant size was much closer to the selected 50,000 FOEB/CD and was therefore probably more accurate.

For lignite there was a slightly larger range of product cost between two studies, $5.70-$6.92 per mBtu for the low CCR and $9.56-$12.24 per mBtu for the high CCR. The range for capital investment was $2.17-$3.00 billion. Since there was some question as to whether the process of the one study[111] was commercially available, the other study (modified Winkler/ICI,[16]), for which its manufacturer is prepared to offer commercial guarantees, was chosen. The costs from this study are shown in Table 16.

In summary, the prices which have been chosen for this study represent two commercially proven gasification technologies, Koppers-Totzek, Lurgi, a modified Winkler, for which its manufacturer will back financially, and the near commercial Texaco gasifier. For bituminous coals, the Koppers-Totzek prices are higher than Texaco because the first operates at atmospheric pressure. In general, the prices for methanol decline as the rank and cost of coal decline.

MTG:

To evaluate the cost of producing gasoline from coal utilizing Mobil's methanol-to-gasoline (MTG) process, two different studies [10,113] were analyzed in the same manner as the methanol studies. Initially, it was assumed that an incremental product cost and capital cost for Mobil's MTG gasoline relative to methanol could be determined from both studies since methanol costs (capital and product) were available for the same technology by the same designers.[10,56] When the cost of gasoline was compared to that of methanol, the incremental cost of gasoline for both studies was very close, confirming the original assumption also shown in Table 16.

The Mobil MTG gasoline prices from one of the studies[10] are shown in Table 16 and should be compared to the Lurgi methanol example because the methanol used was produced in that plant. The product costs for gasoline, SNG, and LPG are respectively $8.01, $6.41, and $6.25 per mBtu for the lower CCR and $14.35, $11.48, and $11.20 per mBtu for the higher CCR. The instantaneous capital investment is $2.95 billion. These prices result in an incremental gasoline cost of $1.45 per mBtu for the lower charge and $2.87 per mBtu for the higher charge. The incremental cost for this plant is $0.34 billion. When comparing these incremental costs with the other Mobil MTG process which does not produce any SNG, the incremental product cost are the same and the incremental capital cost is twice as large. This is logical since the incremental operating and raw materials costs and capital charges for a process unit should roughly double with the doubling of production, thus leaving the incremental product cost per mBtu the same. Likewise, the capital investment would be expected to double and this is why $0.68 billion which is twice the incremental cost of the one half size plant is listed. When the incremental costs of gasoline are applied to the methanol costs, the range for Mobil MTG gasoline would be $7.15-$8.37 per mBtu for the lower CCR and $12.43-$15.11 per mBtu for the higher CCR.

Now that all of the product costs have been determined, a comparison can be made. This comparison must be qualified by the fact that no adjustment has been made between processes except for that already described (e.g., plant size, financial basis, inflation). No attempt has been made to determine if one process design was more thorough or conservative than another. We have relied on the respective engineering firms for thoroughness, accuracy, and good engineering judgment. It can be said that the costs for the Mobil MTG process incremental to methanol were confirmed by both Badger and Mobil, though it is likely that Badger used Mobil's basic design information. Also, the figures for methanol were taken from a large number of studies, and do not represent either the lowest or the highest cost designs. To go beyond this point, one would need to do an in-depth engineering analysis of each process detail, which would probably cost as much as any one of the designs and is beyond the scope of this study.

The cost figures for all five processes are shown in Table 16. As can be seen, the capital costs range from $1.99 billion to $3.4 billion. The methanol plants tend to have the lowest capital costs ($2.0-3.0 billion), while that of the EDS process is in the same range. Using the incremental cost of the MTG process, a gasoline-from-coal plant would cost between $2.7 billion and $3.7 billion. The H-Coal and SRC-II processes are next at $3.3-3.4 billion each. (The capital costs do not include refinery costs since it is unlikely that new refineries would be built.)

The product costs follow a similar pattern, though not exactly. Speaking first of the low cost scenario, methanol is the cheapest product, ranging from $5.70-$7.23 per mBtu for fully commercial gasifiers and $5.90-$6.48 per mBtu for the near-commercial Texaco gasifier. Gasoline via the Mobil MTG process would be $1.45 per mBtu more, or $7.15-$8.68 per mBtu using fully commercial gasifiers and $7.35-$7.93 per mBtu with the Texaco gasifier. H-Coal gasoline costs at $7.79 per mBtu, while SRC-II gasoline is projected to cost $9.87 per mBtu. Finally, EDS gasoline is projected to cost the most of the automotive products at $10.00 per mBtu.

A similar order holds for the higher cost scenario. However, the absolute difference between methanol costs and the cost of gasoline from the other processes increases because the capital cost of the methanol plant is lower. The same is true for MTG gasoline in most cases. A large change occurs in the difference between EDS and H-Coal process costs. While with the low CCR, the EDS costs were 28 percent higher, with the high CCR, they are about 15 percent higher. Also, SRC-II has replaced EDS as the process yielding the highest cost product. This is primarily due to the higher capital costs involved for SRC-II.

In general, it would appear that the indirect coal liquefaction processes can produce usable fuel cheaper than the direct liquefaction technologies.

Methanol from Wood: So far, only methanol from coal has been considered and, indeed, most of the domestic methanol to be produced for fuel will come from coal. While these coal-based cost estimates will be used later in examining the overall economics, it would be helpful to briefly examine the relative cost of methanol from wood and to examine when methanol from wood might be as economical as methanol from coal.

The conversion efficiency for methanol from wood is estimated to be between 48 and 58 percent, which is achievable from coal.[114,115] Some of the estimates for the cost of methanol from wood (per mBtu) are $7.8 (SRI[30,68]), $8.9 (T. Reed[68]), $10 (MITRE[25,68]) and $11.8 (Intergroup/Canada[68]), while the latest figures for methanol from coal are $5.25-6.97/mBtu (for the 0.115 CCR) which were already presented.

A recent report by SERI has compared capital costs vs. plant size (in terms of tons of methanol per day) using cost estimates from the various studies available and has drawn a "best estimate" line through these points.[68] Upon comparison of coal and wood utilization, wood requires about the same capital investment for smaller plants (a 2,000 ton per day methanol facility would cost $220 million for wood and $238 million for coal) and then becomes less expensive than coal for larger plants. However, this advantage cannot effectively be realized, since wood cannot be economically obtained in the large quantities exemplified by coal.

Although the production of methanol from wood will be limited by capital and local wood availability, its economic feasibility will ultimately depend on the relative price of coal and wood. While methanol from coal plants will always be large to take advantage of the economy of scale (15,000-60,000 tons methanol/day), most methanol from wood plants will be relatively small (600-10,000 tons methanol/day) and limited to the amount of readily available biomass. However, since the price of coal could rise faster than that of wood or wood refuse, it may be only a matter of time before methanol from wood will become attractive economically. As an extreme example, using the lowest previously quoted price for methanol of $7.8/mBtu using wood at $30/ton and $7/mBtu for coal at $27.5/ton (and typical relationships between coal price and methanol price), wood could be competitive with coal when the price of coal was $40/ton and wood prices did not increase. This will not happen overnight, but could occur by the time the forest industry could gear up for large-scale methanol production near the end of this century.

B. Distribution

Since distribution systems already exist for gasoline, the short-term economics in this area would, of course, favor the continued use of this fuel over the introduction of methanol. In addition, gasoline also has the advantage of possessing a higher energy density: 115,400 Btu/gal for gasoline compared with 56,560 Btu/gal for methanol. Because transportation costs depend primarily on volume, gasoline would necessarily be less expensive to transport per Btu on a long-term basis.

The costs of distributing a fuel can most easily be divided into three areas; 1) distribution from refinery or plantgate (if no refining is required) to the regional distributor, 2) distribution from the regional distributor to the retailer, and 3) distribution by the retailer (i.e., the gas station). The economics of these three aspects of distribution have been examined in a study by EPA [116], the results of which will be discussed below.

It should be noted that some studies have also included federal and state fuel excise taxes in the cost of distribution. While it is true that excise taxes affect the price of fuel at the pump, these taxes actually represent the cost of building and maintaining roads rather than the cost of using a particular fuel. Taxing fuel is simply the way most governments have chosen to distribute the cost of the particular state or federal highway system. As a switch to methanol should not affect the cost of building or maintaining roads, excise taxes do not need to be considered in this analysis. Also, as demonstrated by the current case with gasohol, excise taxes, or the waiver of them, may be used as an incentive to use a certain fuel. Thus, besides being technically unaffected by a switch of fuels, excise taxes can be manipulated to encourage a public goal and are not even always based on an equitable distribution of highway costs. Because of these reasons, excise taxes will not be considered here.

1. Long-Range Distribution

Two long-range distribution scenarios were analyzed. One represents the transportation costs (1000 miles) from a typical synfuel plant located in the western U.S. (Wyoming), and the other transportation costs from an eastern synfuel plant (Illinois) to nearby markets (100 and 300 miles). Longer pipelines would be needed in the West since major markets are further from the coal fields than they are in the East. The basis for the cost estimates of transporting methanol was a study by DHR, Inc. [117]. Pipeline cost information contained in this study was then used to estimate the cost of transporting synthetic gasoline.

In the eastern scenario, methanol was found to cost $0.56 per mBtu to distribute to a bulk terminal via pipeline, and synthetic gasoline was found to cost $0.37 per mBtu [116]. In the western scenario, the cost of similar methanol distribution was estimated to be $0.73 per mBtu compared to $0.50 per mBtu for gasoline [116]. Nationwide, assuming an equal number of plants in the East and West, long-range distribution of methanol would cost an average of $0.65 per mBtu while synthetic gasoline would cost $0.44 per mBtu. It was assumed that the volume of methanol transported would be twice that of gasoline.

The conversion costs associated with a switch to methanol would be more related to the increase in volumetric capacity than differences in chemical properties. Pipelines and pumps are almost entirely composed of steel or brass, with which methanol is compatible. Rubber seals on pumps may need to be replaced with compounds compatible with methanol, but this should be a minor cost. A second seal may also have to be added to floating roof tanks to prevent the ingress of water.

Since coal-based methanol plants would likely be located near the coal fields and existing petroleum pipelines do not generally service these areas, new pipelines would have to be constructed to transport methanol to the large urban markets. However, the same would be true for coal-based plants producing synthetic gasoline. The capital cost of a methanol pipeline for the western scenario would be approximately $165 million, while that for the gasoline pipeline would be $118 million [116]. The capital cost of the methanol pipeline network for the eastern scenario would be $65 million and that for gasoline would be $46 million [116]. (Each pipeline network would transport 50,000 FOEB/CD of synthetic fuel in each case.) As can be seen, the capital costs are 30 percent less for transporting gasoline than methanol. However, a comparison of these figures with the capital costs of the synfuel plants described earlier shows that: 1) the pipeline costs are less than 10 percent of the production plant costs, and 2) the differences in the pipeline costs are also less than 10 percent of the differences in production plant costs. Thus, the capital costs of producing the synfuels dominate the capital costs of long-range distribution.

2. Local Distribution

As mentioned earlier, local distribution consists of transporting fuel from the regional distributor to the retailers. This distribution is primarily done by tanker truck. While some economy of scale would be realized from the increase in volume accompanying a switch to methanol, the cost of local distribution essentially varies proportionately with distance and volume hauled. Overall, more trips will have to be made overall with methanol than gasoline, since most trucks cannot increase sufficiently in size due to state weight limitations. To be conservative, it was assumed that the cost per volume would remain constant with a switch to methanol and that a typical haul was 50 miles. Local distribution of methanol was then found to cost $0.28 per mBtu while that of synthetic gasoline would cost $0.14 per mBtu.[116]

With respect to local distribution, the cost of conversion to methanol should be small. The only change required to the existing fleet should be new rubber seals and hoses, if they were not already made from a material compatible with methanol. Of course, the size of the existing tanker fleet would also have to be enlarged to handle the increased volume associated with methanol, if the existing tankers could not be used more frequently.

3. Retailer Costs

The costs of retailing fuel are more like that of long-range distribution than local distribution. The costs of retailing are primarily fixed costs, such as land or rent, taxes, lighting, and a minimum level of labor required to operate the station even if only a small number of people buy fuel. Thus, the cost of operating a station would remain essentially constant with a switch to methanol. Also, retailing differs from both long-range and local distribution in that fuel energy is the critical marketing factor, not volume.[116] This is due in part to the intense competition which exists among fuel stations, evidenced by the large number of gas stations which have closed in the last few years. This means that the number of stations retailing fuel depends more on the amount of energy being distributed than on the volume of fuel being distributed. As described earlier, the expected fuel economy advantage of methanol engines is expected to reduce fuel consumption on an energy basis. Thus, the number of fuel retailers could either 1) remain constant with a switch to methanol, or 2) decrease through competition in proportion to the decrease in energy being distributed as methanol relative to the replaced gasoline. If the number of retailers (and the cost of retailing) remains essentially constant with a switch to methanol, the cost per unit energy will increase in proportion to the net reduction in energy being distributed. If, on the other hand, competition reduces the number of stations to compensate for the reduction in energy being distributed in the form of methanol, the cost per unit of energy distributed would remain the same as gasoline. Both outcomes were used to determine a range of possible costs.[116]

Typical retailer mark-ups are estimated to be in the range of $0.05-0.18 per gallon of gasoline.[118] However, since the lower mark-ups are usually associated with the high-volume stations, the average mark-up per gallon of gasoline sold in the U.S. should be nearer to the lower limit, or approximately $0.09 per gallon ($0.76 per mBtu). For methanol, the cost of retailing would lie between this value and 25 percent more since the total amount of energy distributed as methanol would be 20 percent less than that of gasoline due to the expected higher efficiency of methanol engines. Thus, the cost of retailing methanol would be $0.76-0.95 per mBtu.[116]

It should be noted that in the cases of long-range and local methanol distribution, no efficiency improvement was assumed for methanol vehicles. Thus, the volume of methanol distributed was twice that of synthetic gasoline. Although this approach appears inconsistent with that followed to determine retail costs, each procedure is conservative with respect to the estimation of methanol distribution costs. That is, in all instances the assumptions were made which would tend to increase the cost of distributing methanol relative to gasoline. This was done to help assure that the costs of distributing methanol were not underestimated, since some of the costs of conversion are inevitably overlooked.

The only changes in distribution equipment that would be required with a changeover to methanol would be replacement of rubber seals and possibly the hoses on the fuel dispensers (pumps). The underground carbon steel tanks currently used to store gasoline or diesel fuel should be completely compatible with methanol; therefore, tanks that have been previously used for premium leaded or other special blends should be available for methanol storage. (Fiberglass tanks currently used at some stations will not be available for storage of methanol.) The expected increased use of diesel fuel will also compete for these tanks. In the long term, economics will dictate whether or not additional tanks and pumps will be needed and built to satisfy increased demand. Since the possibility exists for more frequent tanker trips to each retailer, more tanks may not be needed. However, it is possible that new tanks would still be built rather than increasing the frequency of tanker trips. However, this should only occur if the cost of more tanks was less than the cost of more frequent trips. Thus, the estimates made here should be sufficient in either case.

4. Total Distribution Costs

The total cost of distributing methanol and gasoline can now be calculated by simply combining the costs presented in the last three sections. Methanol would cost $1.69-1.88 per mBtu to distribute; gasoline would cost $1.34 per mBtu (See Table 17). Gasoline has a significant advantage over methanol in terms of percentage (21-29 percent lower), but the absolute difference is only $0.35-0.54 per mBtu.

Of course, more detail could be added to this analysis to improve the resulting estimates and this will be done in the future. However, the general conclusions should not change substantially.

C. Vehicle Effects

The primary effect that must be examined in this section is the economic effect of changes in the efficiency of the internal combustion engine due to the use of various fuels. A secondary effect would be differences in the cost of such engines.

As has already been discussed in Section IV, the methanol engine may well have a fuel efficiency like that of a diesel, which is 25-30 percent better than that of a gasoline engine.

Table 17

Synthetic Fuel Costs ($ per mBtu)*

	Indirect Coal Liquefaction		Direct Coal Liquefaction
	Methanol	Gasoline	Gasoline
Production			
Plantgate Cost	5.90-12.42	7.35-15.29	7.79-19.06
Distribution			
Long-Range	0.65	0.44	0.44
Local	0.28	0.14	0.14
Retail	0.76-0.95	0.76	0.76
Cost at Pump	7.59-14.30	8.69-16.63	9.13-20.40
Annual Fuel Savings (Relative to Gasoline at $8.69-16.63 per mBtu)**			
	$23-243	$0	$-(20-172)
Added Engine Cost Over Gasoline Engine			
	0	0	0

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* Range of plantgate cost is the lowest cost using the low CCR and the highest cost using the high CCR for bituminous feedstocks.

** Includes effect of increased engine efficiences and differences in at-the-pump fuel costs.

However, since such methanol engines are not available for mass distribution today, this section will use a more conservative fuel efficiency advantage for methanol engines over their gasoline counterparts of 20 percent. Using a fuel economy of 30 miles per gallon for the average gasoline-fueled vehicle, this average vehicle would require about 0.0038 mBtu per mile to operate. A methanol-fueled vehicle would be expected to use at least 20 percent less energy or about 0.0030 mBtu per mile.

Using 12,000 miles per year and the average delivered fuel costs, calculated by combining production and distribution costs, the annual fuel savings relative to gasoline produced via indirect liquefaction (Mobil MTG process) were determined. These savings include two separate effects. One, they include the effect of differences in at-the-pump fuel costs. Two, they also include the effect of methanol engines being more fuel efficient than gasoline engines. For consistency, all fuels were assumed to be derived from bituminous coal. As was pointed out earlier methanol (and hence Mobil gasoline from methanol) can be derived from relatively cheap sources such as lignite. Thus, comparisons between methanol and Mobil MTG gasoline from lignite would be the same as those cited below but gasoline from direct liquefaction would compare less favorably since its costs cited are based on the more expensive bituminous coal. No estimates are available which detail the costs of producing synthetic gasoline by direct liquefaction using other feedstocks.

For example, the annual fuel cost of a vehicle operating on methanol relative to one operating on indirect liquefaction gasoline will be calculated below. Focusing on the upper limit fuel costs of Table 17, methanol at the pump costs $14.30 per mBtu and indirect liquefaction gasoline costs $16.63 per mBtu. The methanol vehicle, having a more efficient engine due to the nature of methanol fuel, uses 0.0030 mBtu per mile, or $0.0429 per mile for fuel. At 12,000 miles per year, the methanol-fueled vehicle consumes $515 worth of fuel annually. The gasoline-fueled vehicle, on the other hand, uses 0.0038 mBtu per mile, or $0.0632 per mile for fuel. At 12,000 miles per year, the annual fuel cost for this vehicle is $758. The difference is $243 per year, which is the upper limit of the range of savings shown in Table 17 for methanol.

Following this procedure and using the lowest fuel cost (based on the low CCR) and the highest fuel cost (based on a 30 percent CCR), methanol would produce a savings of $123-243 per year. Direct liquefaction gasoline would cost an extra $20-172 per year over MTG gasoline, because of its potentially higher at-thepump cost.

To this fuel savings must be added any difference in engine or vehicle cost. While a methanol-fueled diesel engine may be developed with a fuel efficiency advantage comparable to that of a standard diesel, the conservative 20 percent efficiency advantage over the gasoline engine should be attainable with engines similar to the gasoline engine in terms of both design and cost. While a larger fuel tank and a special cold start system may increase costs, savings should be attained with respect to emission control, particularly if NOx reduction catalysts are no longer needed and if base metal oxidation catalysts can be used instead of platinum and paladium. Thus, whether a methanol engine will cost more or less than a gasoline engine in the long run is still an open question at this time. It would be rather safe to project, however, that any potential extra cost would not override the kind of fuel efficiency benefit described earlier.

D. Economics Summary

The results of the past three sections are shown in Table 17. As can be seen when the results are combined, methanol compares favorably to the other fuels. With respect to synthetic gasoline, methanol appears to cost less at the plant gate. This is true whether the low CCR is used or the high CCR. Higher distribution costs lower the difference, but even after distribution, methanol appears to still hold some advantage. This advantage is $1.10-$2.33 per mBtu over MTG gasoline and $1.54-$6.10 per mBtu over direct liquefaction gasoline. Placing this in terms of annual fuel savings, including an allowance for the increased efficiency of a methanol engine, methanol would save $123-$243 per year over MTG gasoline and $143-$415 per year over direct liquefaction gasoline. Without including the increased engine efficiency, these savings would be $50-$106 per year and $70-$278 per year, respectively. Again, it should be stated that no comparison was made between methanol and diesel fuel since none of the coal conversion processes examined produces diesel fuel of sufficient quality for today's diesel engines. All of these economic results are of course subject to the qualifications which have been stated previously; the primary ones being that the detail of the engineering designs could not be standardized across processes and that the cost estimates reflect different points of development for the different synfuel technologies.

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